# Exhibit C

The complete development record of the proposed Reliability Standards

**ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)**
Registered Ballot Body | Related Files | Drafting Team Rosters

**Status**
The drafting team is posting a new SAR and a new proposed version of MOD-030-2, and implementation plan, for a 45-day comment period beginning August 12, 2008. At the same time, the drafting team posted its consideration of the comments it received on the initial ballots for MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 and is proceeding to a recirculation ballot beginning August 12, 2008.

**Purpose/Industry Need**
Requirements 2 and 11 of MOD-030-01 will be modified.

**Status**
The drafting team has posted its consideration of the comments received from the posting of MOD-004 and is posting the standards and associated implementation plan for a 30-day pre-ballot review beginning August 12, 2008

The drafting team has posted the initial ballot results for MOD-001, MOD-008, MOD-028, MOD-029, and MOD-030 and will be considering the comments received with ballots.

The drafting team has posted its consideration of comments from the posting of the MOD standards and the next draft for a 30-day pre-ballot review beginning June 20, 2008.

**Purpose/Industry Need**
The ATC/TTC/AFC Revision SAR proposes changing MOD-001-0 by adding a requirement for transmission providers to coordinate the calculation of ATC and requires that specific reliability practices be incorporated into the ATC calculation and coordination methodologies. Such changes will enhance the reliable use of the transmission system without needlessly limiting commercial activity. This request adds a requirement for documentation of the methodologies used to coordinate ATC. In addition, a requirement is added for the enhanced documentation of the calculation methodology.

The CBM/TRM Revisions SAR proposes changing existing standards on TRM to require crisp and clear documentation of the calculation of TRM and make various components of the methodology mandatory so there is more consistency across methodologies.

| Proposed Standard | Supporting Material | Comment Period | Comments Received | Response to Comments |
|---|---|---|---|---|
| **Project 2006-07 — ATC/TTC and CMB/TRM Posted for Board of Trustees Adoption**<br><br>MOD-001-1<br>Clean \| Redline to last posting<br><br>MOD-008-1 | MOD-001-1 Implementation Plan<br>Clean \| Redline<br>Process Steps<br><br>MOD-008-1 Implementation Plan<br>Clean \| Redline<br>Process Steps<br><br>MOD-028-1 | | | |

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| Clean \| Redline to last posting<br><br>MOD-028-1 Clean \| Redline to last posting<br><br>MOD-029-1 Clean \| Redline to last posting<br><br>MOD-030-1 Clean \| Redline to last posting (Same files as #202-226) | Implementation Plan Clean \| Redline Process Steps<br><br>MOD-029-1 Implementation Plan Clean \| Redline Process Steps<br><br>MOD-030-1 Implementation Plan Clean \| Redline Process Steps | | | |
| Announcement **(227)**<br><br>**Project 2006-07 — ATC/TTC and CMB/TRM10-day Recirculation Ballot Window**<br><br>MOD-001-1Clean **(222)** \| Redline **(223)** to last posting<br><br>MOD-008-1 Clean **(217)** \| Redline **(218)** to last posting<br><br>MOD-028-1 Clean **(212)** \| Redline **(213)** to last posting<br><br>MOD-029-1 Clean **(207)** \| Redline **(208)** to last posting<br><br>MOD-030-1 Clean **(202)** \| Redline **(203)** to last posting | MOD-001-1 Implementation Plan Clean (224) \| Redline (225) Process Steps **(226)**<br><br>MOD-008-1 Implementation Plan Clean **(219)** \| Redline **(220)** Process Steps **(221)**<br><br>MOD-028-1 Implementation Plan Clean **(214)** \| Redline **(215)** Process Steps **(216)**<br><br>MOD-029-1 Implementation Plan Clean **(209)** \| Redline **(210)** Process Steps **(211)**<br><br>MOD-030-1 Implementation Plan Clean **(204)** \| Redline (205) Process Steps **(206)** | **08/12/08 – 08/21/08**<br><br>**Recirculation Ballot** | | |

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| Announcement **(197)**<br><br>**Project 2006-07 — ATC/TTC and CMB/TRM**<br><br>**Posted for 45-day Comment Period**<br><br>MOD-030-2<br>Clean **(195)** \| Redline **(196)** to recirculation version<br><br>SAR Version 1 **(194)** | Implementation Plan **(198)** | **08/12/08 – 09/24/08**<br><br>Electronic Comment Form<br><br>Questions in Word Form **(199)** | Comments **(200)** | Response to Comments **(201)** |
| Announcement **(193)**<br><br>ATC/TTC and CBM/TRM — Project 2006-07<br>10-day Ballot Window<br><br>July 21–July 30, 2008<br>(closed) | | | | |
| Announcement **(192)**<br><br>ATC/TTC and CBM/TRM — Project 2006-07<br>30-day Pre-ballot Review<br><br>June 20–July 21, 2008 | | | | |
| MOD-001-1<br>Clean **(184)** \| Redline **(185)** to last posting | Implementation Plan<br>Clean **(186)** \| Redline **(187)**<br><br>Process Steps **(188)** | | | Initial Ballot Results **(189)**<br><br>Ballot Comments **(190)**<br><br>Response to Comments **(191)** |
| MOD-008-1<br>Clean **(176)** \| Redline **(177)** to last posting | Implementation Plan<br>Clean **(178)** \| Redline **(179)**<br><br>Process Steps **(180)** | | | Initial Ballot Results **(181)**<br><br>Ballot Comments **(182)**<br><br>Response to Comments **(183)** |
| MOD-028-1<br>Clean **(168)** \| | Implementation Plan | | | Initial Ballot Results **(173)** |

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| Redline **(169)** to last posting | Clean **(170)** \| Redline **(171)**<br><br>Process Steps **(172)** | | | Ballot Comments **(174)**<br><br>Response to Comments **(175)** |
| MOD-029-1<br>Clean **(160)** \| Redline **(161)** to last posting | Implementation Plan<br>Clean **(162)** \| Redline **(163)**<br><br>Process Steps **(164)** | | | Initial Ballot Results **(165)**<br><br>Ballot Comments **(166)**<br><br>Response to Comments **(167)** |
| MOD-030-1<br>Clean **(152)** \| Redline **(153)** to last posting | Implementation Plan<br>Clean **(154)** \| Redline **(155)**<br><br>Process Steps **(156)** | | | Initial Ballot Results **(157)**<br><br>Ballot Comments **(158)**<br><br>Response to Comments **(159)** |
| Announcement **(146)**<br><br>30-day Comment Period for Project 2006-07 — ATC/TTC and CMB/TRM<br><br>MOD-004-1<br>Clean **(144)** \| Redline **(145)** to Last Posting<br><br>NOTE: NAESB is in the process of developing the ATC business practices related to transparency and other commercial issues, including postbacks. To view NAESB's current work, please go to http://naesb.org/weq/weq_atc_afc.asp. | Implementation Plan<br>Clean **(147)** \| Redline (**148)** to Last Posting | 05/23/08 – 06/23/08 (closed)<br><br>Comment Form<br><br>Comment Form in Word **(149)** | Comments **(150)** | Consideration of Comments **(151)** |

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| Announcement **(143)**<br><br>30-day Comment Period for Project 2006-07<br>ATC/TTC and CBM/TRM<br><br>April 16-May 15, 2008<br>(closed)<br><br>**NOTE:** NAESB is in the process of developing the ATC business practices related to transparency and other commercial issues, including postbacks. To view NAESB's current work, please go to http://naesb.org/weq/weq_atc_afc.asp. | | | | |
| MOD-001-1<br>Clean **(136)** \|<br>Redline **(137)** to last posting<br><br>NOTE: NAESB is in the process of developing the ATC business practices related to transparency and other commercial issues, including postbacks. To view NAESB's current work, please go to http://naesb.org/weq/weq_atc_afc.asp. | Implementation Plan<br>Clean **(138)** \|<br>Redline **(139)** to Last Posting | Comment Form<br><br>Word Form **(140)** | Comments **(141)** | Consideration of Comments **(142)** |
| MOD-008-1<br>Clean **(129)** \|<br>Redline **(130)** to last posting<br><br>NOTE: NAESB is in the process of developing the ATC business practices related to transparency and other commercial issues, including postbacks. To view NAESB's current work, please go to http://naesb.org/weq/weq_atc_afc.asp. | Implementation Plan<br>Clean **(131)** \|<br>Redline **(132)** to Last Posting | Comment Form<br><br>Word Form **(133)** | Comments **(134)** | Consideration of Comments **(135)** |
| MOD-028-1 | Implementation | Comment Form | Comments | Consideration of |

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| Clean **(122)** \| Redline **(123)** to last posting<br><br>NOTE: NAESB is in the process of developing the ATC business practices related to transparency and other commercial issues, including postbacks. To view NAESB's current work, please go to http://naesb.org/weq/weq_atc_afc.asp. | Plan<br>Clean **(124)** \| Redline **(125)** to Last Posting | Word Form **(126)** | **(127)** | Comments **(128)** |
| MOD-029-1<br>Clean **(115)** \| Redline **(116)** to last posting<br><br>NOTE: NAESB is in the process of developing the ATC business practices related to transparency and other commercial issues, including postbacks. To view NAESB's current work, please go to http://naesb.org/weq/weq_atc_afc.asp. | Implementation Plan<br>Clean **(117)** \| Redline **(118)** to Last Posting | Comment Form<br><br>Word Form **(119)** | Comments **(120)** | Consideration of Comments **(121)** |
| MOD-030-1<br>Clean **(108)** \| Redline **(109)** to last posting<br><br>NOTE: NAESB is in the process of developing the ATC business practices related to transparency and other commercial issues, including | Implementation Plan<br>Clean **(110)** \| Redline **(111)** to Last Posting | Comment Form<br><br>Word Form **(112)** | Comments **(113)** | Consideration of Comments **(114)** |

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| postbacks. To view NAESB's current work, please go to http://naesb.org/weq/weq_atc_afc.asp. | | | | |
| Announcement **(104)**<br><br>Ballot Windows Project 2006-07 - ATC/TTC and CBM/TRM<br><br>March 3-12, 2008 (closed) | | | | Announcement **(105)**<br><br>Initial Ballot Results **(106)**<br><br>Link to Ballot Summary and Comments **(107)** |
| MOD-001-1 Clean **(100)** \| Redline **(101)** to last posting | Implementation Plan **(102)** | | | Consideration of Comments **(103)** |
| MOD-004-1 Clean **(96)** \| Redline **(97)** to last posting | Implementation Plan **(98)** | | | Consideration of Comments **(99)** |
| MOD-008-1 Clean **(92)** \| Redline **(93)** to last posting | Implementation Plan **(94)** | | | Consideration of Comments **(95)** |
| MOD-028-1 Clean **(88)** \| Redline **(89)** to last posting | Implementation Plan **(90)** | | | Consideration of Comments **(91)** |
| MOD-029-1 Clean **(84)** \| Redline **(85)** to last posting | Implementation Plan (**86)** | | | Consideration of Comments **(87)** |
| MOD-030-1 Clean **(80)** \| Redline **(81)** to last posting | Implementation Plan **(82)** | | | Consideration of Comments **(83)** |
| Announcement **(79)**<br><br>Pre-ballot Windows and Ballot Pools Open for Project 2006-07 ATC/TTC and CBM/TRM<br><br>February 1-March 3, 2008 (closed) | | | | |
| MOD-001-1 | Implementation | | | |

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| Clean **(76)** \| Redline **(77)** to last posting | Plan **(78)** | | | |
| MOD-004-1 Clean **(73)** \| Redline **(74)** to last posting | Implementation Plan **(75)** | | | |
| MOD-008-1 Clean **(70)** \| Redline **(71)** to last posting | Implementation Plan **(72)** | | | |
| MOD-028-1 Clean **(67)** \| Redline **(68)** to last posting | Implementation Plan **(69)** | | | |
| MOD-029-1 Clean **(64)** \| Redline **(65)** to last posting | Implementation Plan **(66)** | | | |
| MOD-030-1 Clean **(61)** \| Redline **(62)** to last posting | Implementation Plan **(63)** | | | |
| Announcement **(57)**<br><br>Draft Available Transfer Capability Standards Posted for 45-day Comment Period | | 10/31/07 - 12/14/07 (closed)<br><br>Comment **(58)** Form | Comments **(59)** | Consideration of Comments **(60)** |
| MOD-001-1 **(54)** | Implementation Plan **(55)**<br><br>Summary of FERC Directives in FERC Orders 693 and 890 **(56)** and Corresponding NERC Standards and Requirements | | | |
| MOD-004-1 **(53)** | | | | |
| MOD-008-1 **(52)** | | | | |
| MOD-028-1 **(51)** | | | | |
| MOD-029-1 (revised) **(50)** | | | | |
| MOD-030-1 **(49)** | | | | |
| Announcement **(48)**<br><br>Draft<br>Available Transfer Capability Standards<br>Posted for 30-day Comment Period<br>May 25 through June 25, 2007 (closed) | | | | |
| MOD-001-1 **(44)** | White Paper **(48)** | Comment Form | Comments **(46)** | Consideration of |

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| | | (45) | | Comments (47) |
| MOD-004-1 (39) | | Comment (40) Form<br><br>Attachment 1 (41) | Comments (42) | Consideration of Comments (43) (revised) |
| MOD-008-1 (34) | | Comment (35) Form<br><br>Attachment 1 (36) | Comments (37) | Consideration of Comments (38) |
| MOD-028-1 (30) | | Comment Form (31) | Comments (32) | Consideration of Comments (33) |
| MOD-029-1 (26) | Summary of Changes to the Structure of the Standards for ATC | Comment Form (27) | Comments (28) | Consideration of Comments (29) |
| MOD-030-1 (22) | | Comment Form (23) | Comments (24) | Consideration of Comments (25) |
| Final Supplemental ATC SAR<br><br>Clean (20) \| Redline to last posting (21) | | | | |
| Announcement (15)<br><br>Supplemental ATC SAR (14) | | Comment Form (16)<br><br>Nomination Form (17)<br>05/25/07 - 06/08/07 (closed) | Comments (18) | Consideration of Comments (19) |
| Announcement (10)<br><br>Draft 1 Standard MOD-001-1 Posted for 30-day Comment Period February 15 through March 16, 2007<br><br>MOD-001-1 Clean (8) \| Redline (9) to Version 0 | | 02/15/07 - 03/16/07 (closed)<br><br>Comment Form (11) | Comments (12) | Consideration of Comments (13) |

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| Final SAR: ATC/TTC/AFC **(6)**<br><br>Final SAR: CBM/TRM **(5)** | CBM Minority Opinion **(7)** | | | |
| Draft SAR Version 1: ATC/TTC/AFC Revision **(2)**<br><br>Draft SAR Version 1: CBM/TRM Revision **(1)** | | 07/08/05 - 08/08/05 (closed) | Comments **(3)** | Responses **(4)** |
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**All comments should be forwarded to sarcomm@nerc.net.**
**Questions? Contact Barbara Bogenrief - barbara.bogenrief@nerc.net or 609-452-8060.**

*When completed, email to: gerry.cauley@nerc.net*

## Standard Authorization Request Form

| | |
|---|---|
| Title of Proposed Standard | CBM/TRM Revisions |
| Request Date: | revised June 16, 2005 |

| **SAR Requestor Information** | | **SAR Type** (Put an 'x' in front of one of these selections) |
|---|---|---|
| Name Long Term AFC/ATC Task Force (LTATF) | ☐ | New Standard |
| Primary Contact ltatf@nerc.com | ☒ | Revision to existing Standard |
| Telephone<br>Fax | ☐ | Withdrawal of existing Standard |
| E-mail | ☐ | Urgent Action |

**Purpose/Industry Need** (Provide one or two sentences)

The existing standards on TRM should be revised to require crisp and clear documentation of the calculation of TRM and make various components of the methodology mandatory so there is more consistency across methodologies.

NOTE: the LTATF passed the following strawman by a vote of 15 to 2:

*Because the LTATF debated at length the merits of CBM calculation and utilization, the LTATF asks the SAR Drafting Team (SAR DT) to consider whether the calculation and/or withholding of CBM as an explicit quantity is necessary for reliability and should be part of a reliability standard.* (**please also see appendix F to the Final LTATF report**)

If however, the industry still considers CBM to be necessary, the SAR DT is asked to consider the following recommendations:

The existing standards on CBM should be revised to require crisp and clear documentation of the calculation of CBM and make various components of the methodology mandatory so there is more consistency across methodologies.

### *Reliability Functions*

| **The Standard will Apply to the Following Functions** *(Check box for each one that applies by double clicking the grey boxes.)* | | |
|---|---|---|
| ☐ | Reliability Authority | Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority. |
| ☐ | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time |
| ☐ | Interchange Authority | Authorizes valid and balanced Interchange Schedules |
| ☐ | Planning Authority | Plans the bulk electric system |
| ☐ | Resource Planner | Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area. |
| ☐ | Transmission Planner | Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area. |
| ☒ | Transmission Service Provider | Provides transmission services to qualified market participants under applicable transmission service agreements |
| ☐ | Transmission Owner | Owns transmission facilities |
| ☐ | Transmission Operator | Operates and maintains the transmission facilities, and executes switching orders |
| ☐ | Distribution Provider | Provides and operates the “wires” between the transmission system and the customer |
| ☐ | Generator Owner | Owns and maintains generation unit(s) |
| ☐ | Generator Operator | Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services |
| ☐ | Purchasing-Selling Entity | The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required |
| ☐ | Market Operator | Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch. |
| ☐ | Load-Serving Entity | Secures energy and transmission (and related generation services) to serve the end user |

**<u>Applicability to be determined by SAR DT</u>.**

### *Reliability and Market Interface Principles*

| **Applicable Reliability Principles** *(Check boxes for all that apply by double clicking the grey boxes.)* | |
|---|---|
| ☒ | 1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☒ | 3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☐ | 4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented. |
| ☒ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems. |
| ☒ | 6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis. |

| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)* |
|---|
| 1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes |
| 2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes |
| 3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes |
| 4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes |
| 5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

**Detailed Description** (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

**LTATF proposed changes are highlighted in green**

**SUGGESTED REVISIONS to MOD-004-0**

R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region shall jointly develop and document a CBM methodology. This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

If a RRO's members CBM values are determined by a RTO or ISO, then a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a jointly developed regional methodology.

Each transmission provider not associated with an RTO or ISO shall comply with the methodology jointly developed within its respective reliability region.

Each CBM methodology shall (S1):

R1.1 Specify that the method used to determine generation reliability requirements as the basis for CBM shall be consistent with the respective generation planning criteria.

R1.2 Specify the frequency of calculation of the generation reliability requirement and associated CBM values.

- Require that the calculations must be verified at least annually.
- Require that the dates seasonal CBM values apply must be specified.

R1.3 Require that generation unit outages considered in a transmission provider's CBM calculation be restricted to those units within the transmission provider's system.

**SAR DT should discuss whether CBM should be an explicit reservation and how/if it would be made a requirement. Also, whether the reservations would be a business practice?**

R1.4 Require that CBM be preserved only on the transmission provider's system where the load serving entity's load is located (i.e., CBM is an import quantity only).

**SAR DT should discuss whether there could be a reciprocal agreement for the use of CBM.**

R1.5 Describe the inclusion or exclusion rationale in the CBM calculation for generation resources of each LSE including those generation resources not directly connected to the transmission provider's system but serving LSE loads connected to the transmission provider's system. The following rationale must be included in all methodologies:

R1.5.1 All generation directly connected to the transmission provider's system being used to serve load directly connected to that system will be considered in the CBM requirement determination.

R1.5.2 The availability of generation not directly connected to the transmission provider's system being used to serve load directly connected to that system would be considered available per the terms under which it was arranged.

R1.6 Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system ~~but not obligated to serve Native/Network Load connected to the TSP's system~~. The following rationale must be included in all methodologies:

R1.6.1 The following units shall be included in the CBM requirement determination because they are considered to be the installed generation capacity, committed to serve load, directly connected to the transmission system for which the CBM requirement is being determined:

i. Generation directly connected to the transmission provider's system but not obligated to serve load directly connected to that system, will be incorporated into the CBM requirement determination as follows:

1. Generation directly connected to the transmission provider's system, but committed to serve load on another system, will not be included in the CBM requirement determination for the transmission system to which the generator is directly connected. (**Note to SAR DT – Ensure that this would be consistent with any pending resource adequacy SAR.) These units are not included because they are committed to serve load on another system and therefore not available to serve load on the system for which the CBM requirement is being determined**.)

2. Generation directly connected to the TSP's system, but not committed to serve load on any system, will be included in the CBM requirement determination for the transmission system to which the generator is directly connected as follows:

The TSP will use the best information available to them (i.e. confirmed or requested transmission service/no service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology.

R1.4 Describe the formal process and rationale for the RRO to grant any variances to individual transmission providers from the Regional CBM methodology.

R1.6.1 Require any variances must also be approved by NERC or its designate.

R1.5 Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.

R1.6 Describe the inclusion or exclusion rationale for the loads of each LSE, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).

R1.7 Describe any adjustments to CBM values to account for generation reserve sharing arrangements (i.e. Use of CBM and a reserve sharing event simultaneously occurring that is not planned for). Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

**SAR DT should consider paragraph below:**

R1.8 Require that CBM be based on the required or recommended planning reserve. In other words, a load serving entity that does not arrange for resources at least equal to the recommended or required planning reserve levels does not benefit by causing a higher CBM.

**The SAR DT should consider the option below:**

R1.9 Require that the appropriate entities will plan and reinforce the transmission system for the amount of CBM being preserved.

R2. The ~~RRO's~~ most recent version of the documentation of each entity's CBM methodology shall be available on a web site accessible by NERC, the RROs, and the stakeholders in the electricity market.

M3. Each RRO, in conjunction with its members, shall develop and implement a procedure to review the CBM calculations and values of member transmission providers to ensure that they comply with the Regional CBM methodology and are periodically updated (at least annually) and available to stakeholders. Documentation of the results of the most current Regional reviews shall be provided to NERC or its designate within 30 days of completion.

- The RRO must review and approve the TSP methodology to ensure it is consistent with the RRO's Planning Criteria. The TSP is responsible for ensuring that CBM calculations are consistent with the individual TOs planning criteria.

**Question for SAR DT - Would the above be applicable to the Planning Authority?**

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**REVISIONS to MOD-005-0**

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review (at least annually) the CBM calculations and the resulting values of member Transmission Service Providers ~~to ensure that they comply with the Regional Reliability Organization's CBM methodology~~. The CBM review procedure shall ~~include the following four requirements~~:

R1.1 Indicate the frequency is at least annual, under which the verification review shall be implemented.

R1.2 Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to stakeholders.

R1.3 Require review of the consistency of the transmission provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the same components that comprise CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process. The procedure must specify how the consistency would be verified.

**The SAR DT should consider the options below:**

R1.3.1 Require verification that the appropriate entities are planning and reinforcing the transmission system for the amount of CBM being preserved. The procedure must specify how the verification would be determined. Transmission service providers must also perform this verification and report on the findings as specified below.

R1.4 Require CBM values to be updated at least annually and available to the Regions, NERC, and stakeholders in the electricity markets.

R2. The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days).

R3. Documentation of the results of the most current implementation of the procedure shall be sent to NERC within 30 days of completion.

**REVISIONS to MOD-006-0**

**Note to SAR DT: Use of CBM should be addressed under business practices and not be part of this standard - consider the withdrawal of MOD-006-0 and transfer to NAESB.**

**REVISIONS to MOD-008-0**

R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region in conjunction with its members, shall jointly develop and document a TRM methodology. This methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. If a RRO's members TRM values are determined by a RTO or ISO, than a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a regional methodology.

Each TRM methodology shall:

R1.1 Specify the update frequency of TRM calculations.

- Require that calculations be verified at least annually if determined to be required
- Require that dates that seasonal TRM values apply must be specified

R1.2 Specify how TRM values are incorporated into ATC calculations.

R1.3 Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM:

R1.3.1 aggregate load forecast error (not included in determining generation reliability requirements).
R1.3.2 load distribution error.
R1.3.3 variations in facility loadings due to balancing of generation within a Balancing Authority Area.
R1.3.4 forecast uncertainty in transmission system topology.
R1.3.5 allowances for parallel path (loop flow) impacts.
R1.3.6 allowances for simultaneous path interactions.
R1.3.7 variations in generation dispatch
R1.3.8 short-term operator response (operating reserve actions not exceeding a 59-minute window).
R1.3.9 Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.
R1.3.10 Additional detail on how variations in generation dispatch are handled from intermittent generation sources such as wind and hydro, need to be provided.

R1.4 Describe the conditions, if any, under which TRM may be available to the market as Non-Firm Transmission Service.

R1.5 Describe the formal process for the granting of any variances to individual transmission service providers from the regional TRM methodology.

R1.5.1 Any variances must also be approved by NERC or its designate

R1.6 Describe the methodology and conditions thereof that are used to reflect if TRM is reduced for the operating horizon.

R1.7 Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

**SAR DT should consider paragraph below:**

R1.8 Specify TRM methodologies and values must be consistent with the approved planning criteria.

R1.8.1 Require that the appropriate entities will plan and reinforce the transmission system for the amount of TRM being preserved. The methodology must specify how the verification of the consistency would be determined.

R1.8.2 Each TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are entity specific or that are considered in each respective methodology shall also be explained along with their use in determining TRM values.

**REVISIONS to MOD-009-0**

R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region , in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and resulting values of member transmission providers to ensure that they comply with the regional TRM methodology and are updated at least annually and available to transmission users.

**The SAR DT should consider ways to ensure adherence with the paragraph below:**

- The RRO must review and approve the transmission service provider(s)' methodology to ensure it is consistent with the RRO's Planning Criteria. The RRO is responsible for ensuring that TRM calculations are consistent with the individual TOs planning criteria.

The TRM review procedure shall:

R1.1 Indicate the frequency is at least annual, under which the verification review shall be implemented.

R1.2 Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to stakeholders.

R1.3 Require review of the consistency of the transmission service provider's or Transmission Owner's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process. The review process used by a transmission service provider or transmission owner also needs to be documented.

R1.3.1 Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

SAR DT to review paragraph below:

R1.4 TRM methodologies and values must be consistent with the applicable planning criteria

- The methodology must specify how the verification of the consistency would be determined

R2. The documentation of the regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC within 30 days of completion.

R3. Documentation of the results of the most current regional reviews shall be provided to NERC within 30 days of completion.

R4. Require TRM values to be verified at least annually and made available to the RROs, NERC, and stakeholders.

### *Related Standards*

| Standard No. | Explanation |
|---|---|
| t.b.d | LTATF SAR for ATC and TTC (submitted with this SAR). |
| R05004 | NAESB proposed Business Practice for a single Business Practice Standard to be developed related to both:<br>1) the processing and evaluation of transmission service requests, which use TTC/ATC/AFC and CBM/TRM<br>2) the processing and evaluation of request(s) to schedule against approved transmission service reservation(s). |
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### *Related SARs*

| SAR ID | Explanation |
|---|---|
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### *Regional Differences*

| Region | Explanation |
|---|---|
| ECAR | |
| ERCOT | |
| FRCC | |
| MAAC | |
| MAIN | |
| MAPP | |
| NPCC | |
| SERC | |
| SPP | |
| WECC | |

### *Related NERC Operating Policies or Planning Standards*

| ID | Explanation |
|---|---|
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*When completed, email to: gerry.cauley@nerc.net*

## Standard Authorization Request Form

| | |
|---|---|
| Title of Proposed Standard | ATC/TTC/AFC Revisions |
| Request Date | Revised June 16, 2005 |

| **SAR Requestor Information** | **SAR Type** (Put an 'x' in front of one of these selections) | |
|---|---|---|
| Name Long Term AFC/ATC Task Force (LTATF) | ☐ | New Standard |
| Primary Contact LTATF@nerc.com | ☒ | Revision to existing Standard |
| Telephone<br>Fax | ☐ | Withdrawal of existing Standard |
| E-mail | ☐ | Urgent Action |

**Purpose/Industry Need** (Provide one or two sentences)

This request changes existing modeling standard(s) by adding a requirement for transmission providers to coordinate the calculation of ATC and requires that specific reliability practices be incorporated into the ATC calculation and coordination methodologies. Such changes will enhance the reliable use of the transmission system without needlessly limiting commercial activity. This request adds a requirement for documentation of the methodologies used to coordinate ATC. In addition, a requirement is added for the enhanced documentation of the calculation methodology.

### *Reliability Functions*

| **The Standard will Apply to the Following Functions** *(Check box for each one that applies by double clicking the grey boxes.)* | | |
|---|---|---|
| ☐ | Reliability Authority | Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority. |
| ☐ | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time |
| ☐ | Interchange Authority | Authorizes valid and balanced Interchange Schedules |
| ☐ | Planning Authority | Plans the bulk electric system |
| ☐ | Resource Planner | Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area. |
| ☐ | Transmission Planner | Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area. |
| ☒ | Transmission Service Provider | Provides transmission services to qualified market participants under applicable transmission service agreements |
| ☐ | Transmission Owner | Owns transmission facilities |
| ☐ | Transmission Operator | Operates and maintains the transmission facilities, and executes switching orders |
| ☐ | Distribution Provider | Provides and operates the “wires” between the transmission system and the customer |
| ☐ | Generator Owner | Owns and maintains generation unit(s) |
| ☐ | Generator Operator | Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services |
| ☐ | Purchasing-Selling Entity | The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required |
| ☐ | Market Operator | Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch. |
| ☐ | Load-Serving Entity | Secures energy and transmission (and related generation services) to serve the end user |

Pending resolution of the FMSCTF, might also apply to Transmission Planner and Planning Authority and Reliability Regions.

### *Reliability and Market Interface Principles*

| **Applicable Reliability Principles** *(Check boxes for all that apply by double clicking the grey boxes.)* | |
|---|---|
| ☒ | 1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☒ | 3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☐ | 4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented. |
| ☐ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems. |
| ☒ | 6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis. |

| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)* |
|---|
| 1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes |
| 2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes |
| 3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes |
| 4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes |
| 5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

**Detailed Description** (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

Definitions of Terms used in standard:

The Drafting Team should finalize the definitions for TTC, ATC, AFC.

The Drafting Team should finalize the criteria for determining flowgates

The Drafting Team should add a requirement for transmission providers to coordinate the calculation of ATC and require that specific reliability practices be incorporated into the ATC calculation and coordination methodologies.

The Drafting Team should add a requirement for the enhanced documentation of the ATC calculation methodology.

Strawman Definitions from LTATF are contained in the Appendix:

----------------------------------------------------------------------

**Additions/changes from existing standard in green, recommended by LTATF**

**B. Requirements**

MOD-001-0 Requirement 1 (R1). Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region, shall jointly develop and document a TTC and ATC (which may include the calculation of AFC) methodology.

> If the transmission service providers/and or AFC/ATC/TTC calculators' AFC, TTC and ATC values are determined by a RTO or ISO, then a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a jointly developed regional methodology.
>
> Each transmission provider not associated with an RTO or ISO shall comply with the methodology jointly developed by the group of transmission service providers/and or AFC/ATC/TTC calculators within its respective reliability region.
>
> This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

Each TTC and ATC methodology shall:

R1.1 Include a narrative explaining how TTC and ATC values are determined and in evaluating a transmission service request and made available to customers. In addition, an explanation for all items listed here must also be included of any process that produces values that can override the TTC, AFC and ATC values.

R1.2 Account for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the transmission provider's system, are included. An explanation must be provided on how reservations that exceed the capability of the specified source point are accounted for. (e.g. 500 MW of transmission service exists in each of three directions sourced from a generator with a capacity of 500 MW).

R1.3 Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations. Source and sink points are further defined in the Source and Sink Points white paper contained in Appendix B of the Final LTATF Report.

R1.4 Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)

R1.5 Require that ATC values and postings be updated at a minimum frequency to assure proper representation of the transmission system. These values will be made available to stakeholders at a similar frequency.

R1.6 Indicate the treatment and level of customer demands, including interruptible demands.

R1.7 Require that the data listed below, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used. Entities requiring data should request the data as needed. (SAR DT to determine to whom this applies, who supplies – who uses). In addition, specify how this information is coordinated and used to determine TTC and ATC values. If some data is not used or coordinated, provide an explanation. The required minimum update frequency[1] for each item is listed below:

R1.7.1 **Generation Outage Schedules**: Minimum 13 month time frame includes all generators (SAR DT to determine MW threshold) used in the ATC/AFC calculation). The update frequency is daily.

R1.7.2 **Generation dispatch order**: generic dispatch participation factors on a control area/market basis. The update frequency is as required.

R1.7.3 **Transmission Outage Schedules**: Minimum 13 month time frame, updated daily for all bulk electric system facilities that impact ATC/AFC calculations; updated once an hour for unscheduled outages. (SAR DT should consider both pending and approved outages)

R1.7.4 **Interchange Schedules** : The update frequency is hourly.

[1] The update frequency specified should allow for improvements in technology, communication, etc, that might better represent actual system conditions.

R1.7.5 **Transmission Reservations**: The update frequency is daily.

R1.7.6 **Load Forecast**: supplied via the SDX(or similar method), includes hourly data or peak with profile for the next 7-day time frame. The update frequency is daily. **In addition, daily peak for day 8 to 30 updated at least daily, and monthly for next 12 months updated monthly.**

R1.7.7 **Flowgate AFC:** Firm and non-firm AFC values will be exchanged between entities that have coordination agreements. Unless otherwise specified in the coordination agreement, the minimum update frequency is as follows: Hourly AFC once-per-hour, Daily AFC once-per-day and Monthly AFC once-per-week.

R1.7.8 **Flowgate rating**: Seasonal flowgate ratings will also be provided. Updated as required.

R1.7.9 **Calculation model**: Updated model will be made available to neighboring/affected calculators.

R1.7.10 Flowgates and flowgate definitions/criteria should be exchanged with neighboring/affected calculators on a seasonal basis, or more often as required to represent actual system conditions.

**(SAR DT should discuss establishing defined criteria for establishing flowgates consistent with regional operating and planning practices)**

R1.8 Describe how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.

R1.9 Describe assumptions used for positive impacts and counterflow of transmission reservations, including the basis for the assumptions.

R1.10 Describe assumptions used for generation dispatch for both external and internal systems for base case dispatch and transaction modeling, including the basis for the assumptions.

R1.11 Ensure that the TTC/ATC calculations are consistent with the Transmission Owner's/Transmission Planner's (leave FM designation to SAR DT) planning and operating criteria. **(SAR DT: see Appendix E of final LTATF report dealing with consistency with planning criteria)**

R1.12 Describe the formal process for the granting of any variances to individual transmission providers from the jointly developed regional TTC/ATC methodology.

- Any variances must be approved by NERC or its designate

R2. The most recent version of the documentation of each TTC and ATC methodology shall be available on a web site accessible by NERC, the Regions, and the stakeholders in the electricity market.

R3. Each TTC and ATC methodology shall address each of the items listed above and shall explain its use in determining TTC and ATC values.

C. Measures.

~~M1. The Regional Reliability Organization shall provide evidence that its most recent TTC and ATC methodology documentation meets Reliability Standard MOD-001-0_R1.~~

~~M2. The Regional Reliability Organization shall provide evidence that its TTC and ATC methodology is available on a web site accessible by NERC, the Regional Reliability Organizations, and transmission users.~~

(**SDT to develop procedures for audit to ensure adherence to stated methodology**)

**Moved to appendix per suggestion from SAC**

a)

***Related Standards***

| Standard No. | Explanation |
|---|---|
| MOD-002-0 | Review of TTC and ATC Calculations and Results |
| | |
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| | |

***Related SARs***

| SAR ID | Explanation |
|---|---|
| T.B.D | LTATF SAR for TRM and CBM (submitted with this SAR) |
| R05004 | NAESB proposed Business Practice for a single Business Practice Standard to be developed related to both:<br>1) the processing and evaluation of transmission service requests, which use TTC/ATC/AFC and CBM/TRM<br>2) the processing and evaluation of request(s) to schedule against approved transmission service reservation(s). |
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## *Regional Differences*

| Region | Explanation |
|---|---|
| ECAR | |
| ERCOT | |
| FRCC | |
| MAAC | |
| MAIN | |
| MAPP | |
| NPCC | |
| SERC | |
| SPP | |
| WECC | |

## *Related NERC Operating Policies or Planning Standards*

| ID | Explanation |
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# Appendix

**<u>Strawman Definitions from LTATF:</u>**

Total Transfer Capability (TTC):

TTC and ATC are defined in standard 1E1
Existing Transmission Commitments (ETC)
ATC is expressed as:
ATC = TTC – Existing Transmission Commitments ) – CBM – TRM

Flowgate is the name given to the transmission element(s) and associated contingency(ies) if any, that may limit transfer capability.

Flowgate Criteria – to be determined by SDT

Available Flowgate Capability (AFC)
AFC is expressed as:
AFC = [to be finalized by SARDT]

The relationship between ATC and AFC is as follows:

$ATC_{(\text{Path A-B})}=AFC_{(\text{Most Limiting Flowgate for Path A-B})}/\text{Distribution Factor}_{(\text{Path A-B on Limiting Flowgate})}$

Daily, Monthly, Yearly TTC
Daily, Monthly, Yearly ATC
Daily, Monthly, Yearly TRM
Daily, Monthly, Yearly CBM

**LTATF Suggested Audit Methodology**

M1. Each group of transmission service providers within a region, in conjunction with the members of that region, shall jointly develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC methodology, the NERC Planning Standards, and applicable Regional criteria.

M2. A review to verify that the ATC/TTC calculations are consistent with the TO’s/TP’s planning criteria is also required. The procedure used to verify the consistency must also be documented in the report. Documentation of the results of the most current reviews shall be provided to NERC within 30 Days of completion.

M3. Each entity responsible for the TTC and ATC methodology, in conjunction with its members and stakeholders, shall have and document a procedure on how stakeholders can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission provider(s), and how these concerns or questions will be addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the stakeholders in the electricity market.

M4. The RRO must review and approve the ATC/TTC methodology to ensure it is consistent with the RRO's Planning and Operating Criteria.

The RRO is responsible for ensuring that TTC and ATC calculations are consistent with the individual TOs/TPs planning criteria.

Each procedure shall specify:

b) The name, telephone number, and email address of a contact person to whom concerns are to be addressed.

c) The amount of time it will take for a response.

d) The manner in which the response will be communicated (e.g., email, letter, telephone, etc.)

e) What recourse a customer has if the response is deemed unsatisfactory.

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
**and**
**Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0**

This form is to be used to submit comments on Draft 1 of two individual SARs: 1) Proposed Revisions to Existing Standard Number MOD-001-0 dealing with AFC/ATC/TTC; and 2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 dealing with CBM/TRM. Comments must be submitted by **August 08, 2005**. You may submit the completed form by emailing it to: sarcomm@nerc.com with the words "ATC/TTC/CBM/TRM Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

**ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE AND IT IS THEREFORE IMPORTANT TO ADHERE TO THE FOLLOWING REQUIREMENTS:**

**DO:** **Do** enter text only, with no formatting or styles added.
**Do** use punctuation and capitalization as needed (except quotations).
**Do** use more than one form if responses do not fit in the spaces provided.
**Do** submit any formatted text or markups in a separate WORD file.

**DO NOT:** **Do not** insert tabs or paragraph returns in any data field.
**Do not** use numbering or bullets in any data field.
**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Ronald Szymaczak |
| Organization: | Exelon |
| Telephone: | 630-437-2795 |
| Email: | ronald.szymczak@exeloncorp.com |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☐ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☐ | 4 - Transmission-dependent Utilities |
| ☐ MAIN | ☐ | 5 - Electric Generators |
| ☐ MAPP | ☐ | 6 - Electricity Brokers, Aggregators, and Marketers |
| ☐ NPCC | ☐ | 7 - Large Electricity End Users |
| ☐ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact Email:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information:

The Long-Term AFC/ATC Task Force (LTATF) was formed to develop specific recommendations for the calculation and coordination of AFC/ATC with the goal of increasing market liquidity and enhancing grid reliability. The task force's work was coordinated with NAESB to separate business practices from reliability concerns. The LTATF evaluated the results of the short-term recommendations in the Alliant West area for summer 2004, and used this evaluation when considering whether to recommend the Alliant West short-term recommendations continue.

In developing their recommendations the LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for ATC/TTC and CBM/TRM. The proposed "Modification to MOD-001-0 Documentation of ATC and TTC Calculation" SAR and "Modification to standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 SAR are the culmination[1] of the LTATF's work and is the subject matter for this Comment Form.

The SAC and the LTATF would like to receive industry comments on the scope and need for these two individual SARs. Accordingly, we request your comments included on this form, emailed to sarcomm@nerc.com with the subject "ATC/TTC/CBM/TRM Comments" by **August 7, 2005**.

## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
| | | R1.9 | Add/Delete Language |
| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

**1. Is there a reliability need for the proposed standard?**

☐ Yes

☐ No

Comments:

**2. Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

☐ Yes

☒ No

Comments: The standard must state that aspects of the calculation ciritcal to the reliability be required in the methodologies. Some examples of the aspects critical to reliability are exchange and use of data, monitoring all critical flowgates and meeting a minimum frequency of calculation. These items and any others must be required in the methodologies. What method the ATC calculator uses to accomplish these critical aspects is up to them and therefore a standard method should not be required.

**3. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments:

**4. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**5. Do you agree with the list of entities to which the standard would apply?**

☒ Yes
☐ No

Comments:

**6. Do you have any other terms that should be included in the definitions?**

☐ Yes
☒ No

Comments:

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes
☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments: ATC/TTC SAR does not require a RTO or ISO to have a methodology that meets the requirements in this proposed standard. The followin wording changes (noted in CAPITALS) to section B-R1 are recommended.

MOD-001-0 Requirement 1 (R1). Each group of transmission service providers and/or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region shall pointly develop and document a REGIONAL TTC and ATC (which may include the calculation of ATC) methodology.

If the transmission service providors and/or AFC/ATC/TTC calculators' AFC, TTC, and ATC values are determined by RTO or ISO, then a jointly developed regional metodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a jointly developed regional methodology. A RTO OR ISO THAT CALCULATES AFC/ATC/TTC IS REQUIRED TO HAVE A WRITTEN METHODOLOGY DOCUMENT THAT MEETS THE REQUREMENTS SPECIFIED IN THIS STANDARD.

M2 needs to specify that RTOS AND ISOS WILL ALSO BE REQUIRED TO PERFORM THIS REVIEW OF CONSISTENCY WITH PLANNING CRITERIA AND DOCUMENT THE RESULTS. If this requrement is not added, ther is no check on the consistancy with planning criteria for members who are not under the regional methodology but under a RTO or ISO methodology.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☒ Yes
☐ No
Comments:

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes

☐ No

Comments: Earlier in the development of this industry, there were predominately 'local' vertically integrated electric utilities. Each utiltiy built sufficient generation to serve its own load responsibility. Transmission interconnections with neighboring utilities were typically established for one of the following reasons:

First, to minimize duplication of trasmission (ie. tie to neighbor for trasmission reliability.)

Second, was an economic descision to build transmission instead of generation based on the generation reqliablity criteria the utility planned for (ie. tie to neighbor to meet generation reliability criteria.)

This second reason is the origin of the CBM concept. Transmission interconnections provide easch interconnected system with access to their neighbors so that in the event of an extreme generation outage within a utility, that temporarily generation deficient utility could have access to 'emergency' generation resources from their interconnected neighbors. CBM is the quantification of this use of the transmission system. Therefor CBM is an 'emergency' use transmission quantity and only 'exists' on the importing system for use only during periods of an emergency generation deficiency when firm transmission service is not available. Just as transmission capacity is preserved for the generation contingencies a utility planned for, transmission capacity is also preserved for the generation contingencies that are planned for. In either case, the utility constomers paid for the transmission capacity that was installed to maintain the reliability level that is planned for, via their rates for service.

**11. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments:

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**13. Do you agree with the list of entities to which the standard would apply?**

☒ Yes
☐ No

Comments:

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes
☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments: CBM/TRM SAR does not require a RTO or ISO to have a methodology that meets the requirements in this proposed standard. The following word changes (noted in CAPITALS) to section R1 of the CBM portion are recommended -

R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region shall jointly develop and document a REGIONAL CBM methodology. This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

If a RRO's members CBM values are determined by a RTO or ISO, then a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a jointly developed regional methodology.   A RTO OR ISO THAT CALCULATES CBM AND OR TRM IS REQUIRED TO HAVE A WRITTEN METHODOLOGY DOCUMENT THAT MEETS THE REQUIREMENTS SPECIFIED IN THIS STANDARD.

M4 needs to specify that THE RRO MUST REVIEW AND APPROVE THE  RTO OR ISO CBM METHODOLOGY TO ENSURE IT IS CONSISTENT WITH THE RRO'S PLANNING ABD OPERATING CRITERIA.  If this requirement is not added there appears to be no check of a RTO or ISO' ATC/TTC methodology.

CBM/TRM SAR does not require a RTO or ISO to have a methodology that meets the requirements in this proposed standard.  The following wording changes (noted in CAPITALS) to section  R1 of the TRM portion are recommended :

R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region in conjunction with its members, shall jointly develop and document a REGIONAL TRM methodology. This methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. If a RRO's members TRM values are determined by a RTO or ISO, than a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a regional methodology.  A RTO OR ISO CALCULATES CBM AND OR TRM IS REQUIRED TO HAVE A  METHODOLOGY DOCUMENT THAT MEETS THE REQUIREMENTS SPECIFIED IN THIS STANDARD.

In addition, the  text in section R1 of the SAR needs to be revised to clarify that the following reviews are done by the RRO. First, the RRO needs to review the calculations of transmission providers under the regional methodology to ensure they are adhereing to the regional methodology.     Second, the RRO must review the transmission service provider(s)' not under the regional methodology to ensure that their methodology is consistent with the RRO's Planning Criteria. Finally, the RRO is responsible for ensuring that TRM calculations done by transmission service providers', regardless of what methodology they are under, are consistent with the individual TOs planning criteria.          The following wording changes noted in CAPITALS are recommended:

The RRO must review and approve the METHODOLOGY OF transmission service provider(s)' NOT UNDER THE REGIONAL  methodology to ensure it is consistent with the RRO's Planning Criteria. The RRO is responsible for ensuring that TRM calculations are consistent with the individual TOs planning criteria.

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
**and**
**Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0**

This form is to be used to submit comments on Draft 1 of two individual SARs: 1) Proposed Revisions to Existing Standard Number MOD-001-0 dealing with AFC/ATC/TTC; and 2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 dealing with CBM/TRM. Comments must be submitted by **August 08, 2005**. You may submit the completed form by emailing it to: sarcomm@nerc.com with the words “ATC/TTC/CBM/TRM Comments” in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

**ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE AND IT IS THEREFORE IMPORTANT TO ADHERE TO THE FOLLOWING REQUIREMENTS:**

**DO:**
- **Do** enter text only, with no formatting or styles added.
- **Do** use punctuation and capitalization as needed (except quotations).
- **Do** use more than one form if responses do not fit in the spaces provided.
- **Do** submit any formatted text or markups in a separate WORD file.

**DO NOT:**
- **Do not** insert tabs or paragraph returns in any data field.
- **Do not** use numbering or bullets in any data field.
- **Do not** use quotation marks in any data field.
- **Do not** submit a response in an unprotected copy of this form.

| Individual Commenter Information<br>(Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| Email: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☒ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☐ | 4 - Transmission-dependent Utilities |
| ☐ MAIN | ☐ | 5 - Electric Generators |
| ☐ MAPP | ☐ | 6 - Electricity Brokers, Aggregators, and Marketers |
| ☐ NPCC | ☐ | 7 - Large Electricity End Users |
| ☐ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** FRCC

**Lead Contact:** **John Odom**

**Contact Organization:** **FRCC**

**Contact Segment:** **2**

**Contact Telephone:** **813-289-5644**

**Contact Email:** **jodom@frcc.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| **Tom Washburn** | **OUC** | **FRCC** | **3** |
| **Gary Brinkworth** | **City of Tallahassee** | **FRCC** | **1** |
| **Paul Elwing** | **Lakeland Electric** | **FRCC** | **3** |
| **5Carter Edge** | **Southeaster Power Administration** | **FRCC** | **4** |
| **Roger Westphal** | **Gainesville Regional Utilities** | **FRCC** | **3** |
| **Bob Schoneck** | **Florida Power & Light** | **FRCC** | **3** |
| **Don McInnis** | **Florida Power & Light** | **FRCC** | **1** |
| **Kiko Barredo** | **Florida Power & Light** | **FRCC** | **3** |
| **Paul Graves** | **Progress Energy Florida** | **FRCC** | **3** |
| **Ron Donahey** | **Tampa Electric Company** | **FRCC** | **3** |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information:

The Long-Term AFC/ATC Task Force (LTATF) was formed to develop specific recommendations for the calculation and coordination of AFC/ATC with the goal of increasing market liquidity and enhancing grid reliability. The task force's work was coordinated with NAESB to separate business practices from reliability concerns. The LTATF evaluated the results of the short-term recommendations in the Alliant West area for summer 2004, and used this evaluation when considering whether to recommend the Alliant West short-term recommendations continue.

In developing their recommendations the LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for ATC/TTC and CBM/TRM. The proposed "Modification to MOD-001-0 Documentation of ATC and TTC Calculation" SAR and "Modification to standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 SAR are the culmination[1] of the LTATF's work and is the subject matter for this Comment Form.

The SAC and the LTATF would like to receive industry comments on the scope and need for these two individual SARs. Accordingly, we request your comments included on this form, emailed to sarcomm@nerc.com with the subject "ATC/TTC/CBM/TRM Comments" by **August 7, 2005**.

## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
| | | R1.9 | Add/Delete Language |
| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

1. **Is there a reliability need for the proposed standard?**

   ☒ Yes

   ☐ No

   Comments: Reliability must be maintained at all times including accounting for planned outages and unexpected dynamic system conditions, while at the same time providing for ATC/AFC to users of the the system. Therefore there is a reliability need for this standard. A transmission system has finite capability and the provision for a transmission reliability margin (TRM) is an important component in determining ATC/AFC and is necessary to take into account such varied system conditions in order to maintain reliability while not overstating the ATC/AFC. However, the ATC values are not reliability indicators, but rather the ATC values are derived from reliability based values, assumptions and criteria.

2. **Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

   ☐ Yes

   ☒ No

   Comments: The proposed standard should require that ATC/AFC values be coordinated across interfaces. The standard should not require one specific uniform methodology for each ATC/AFC calculator for calculating ATC, AFC and TTC, but should require that the Regional Reliability Organizations (including RTO/ISOs) develop a region wide methodology that meets the needs of each respective Planning Authority within the region, such that when applied by individual ATC/AFC calculators would produce consistent results at all interfaces.

3. **Do you agree with the scope of the proposed standard?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

   **Note: NAESB has a proposal for companion business practice - R05004)**

   ☐ Yes

   ☒ No

Comments: No, it is not necessary, but to the extent some sort of business issues need to be addressed, such as response times for OASIS requests, it should be limited strictly to business practices, and not address reliability issues.

**5. Do you agree with the list of entities to which the standard would apply?**

☐ Yes
☒ No

Comments: This standard should also apply to the Planning Authority and the Reliability Regions.

**6. Do you have any other terms that should be included in the definitions?**

☐ Yes
☒ No

Comments:

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes
☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments: Requirement R1.11 states "Ensure that the TTC/ATC calculations are consistent with the TO/TP planning and operating criteria." The standard must be more descriptive about the relationship between these calculations and their consistency with the appropriate planning criteria. The basic criteria utilized for determining acceptable reliability levels should be consistent, but the assumptions and conditions evaluated may be somewhat different to take into account short-term or real-time system conditions as compared to long term planning assumptions. The time horizons for each process will create differences that must be recognized. In many cases, there will be situations that exist in the short term that were not anticipated or modeled in the longer term (> than 1 year) planning cases, such as, planned or unplanned generator outages or line outages. However, the system security must be evaluated with these outages if they extend over the study period when calculating ATC.

Requirement R1.5 states "Require that ATC values and posting be updated at a minimum frequency to assure proper representation of the transmission system. These values will be made available to stakeholders at a similar frequency". This requirement should not establish a minimum frequency for updating or posting, rather, it should require a minimum frequency of review, with update and posting, only if necessary. It is imperative that the standard establish frequency minimums and timings that are practical and meaningful. Requirement R1.7 specifies minimum update frequencies for 10 items. The standard should be very clear that if values have not changed from the previous posting, such as in the case where there are not any unscheduled transmission outages (R1.7.3), there is not a requirement to post an update.

Requirement R1.7 states "Require that the data listed below, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used." Add the words "by transmission providers" to the end of the sentence above. This addition will ensure that there is not a requirement to share this sensitive data with the public.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments: Reliability must be maintained at all times including accounting for planned outages and unexpected dynamic system conditions, while at the same time providing for ATC/AFC to users of the the system. Therefore there is a reliability need for this standard. A transmission system has finite capability and the provision for a transmission reliability margin (TRM) is an important component in determining ATC/AFC and is necessary to take into account such varied system conditions in order to maintain reliability while not overstating the ATC/AFC.

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes

☐ No

Comments: Since CBM is an "implied" reservation of a portion of the transmission capability it is important to include it an ATC calculations to ensure reliability.

**11. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments:

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments: No, it is not necessary, but to the extent some sort of business issues need to be addressed, such as response times for OASIS requests, it should be limited strictly to business practices, and not address reliability issues. Additionally, TRM is a reliability quantity and therefore would be inappropriate for NAESB to have a parallel standard.

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes
☒ No

Comments: This standard should also apply to the Planning Authority and the Reliability Regions.

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes
☒ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes
☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments: "MOD-008-1 R1.5.1 Any variances must also be approved by NERC or its designate. Delete this requirement. Variances should be approved by the Regional Reliability Organizations, not NERC, since the RROs have an approved methodology."

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
**and**
**Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0**

This form is to be used to submit comments on Draft 1 of two individual SARs: 1) Proposed Revisions to Existing Standard Number MOD-001-0 dealing with AFC/ATC/TTC; and 2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 dealing with CBM/TRM. Comments must be submitted by **August 08, 2005**. You may submit the completed form by emailing it to: sarcomm@nerc.com with the words "ATC/TTC/CBM/TRM Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

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**Do not** use numbering or bullets in any data field.
**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Soulier Daniel Victor Bissonnette | |
| Organization: | Hydro-Québec TransÉnergie | |
| Telephone: | (514) 289-3123 | |
| Email: | soulier.daniel@hydro.qc.ca bissonnette.victor@hydro.qc.ca | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☒ | 1 - Transmission Owners |
| ☐ ECAR | ☐ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☐ | 4 - Transmission-dependent Utilities |
| ☐ MAIN | ☐ | 5 - Electric Generators |
| ☐ MAPP | ☐ | 6 - Electricity Brokers, Aggregators, and Marketers |
| ☒ NPCC | ☐ | 7 - Large Electricity End Users |
| ☐ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact Email:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information:

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In developing their recommendations the LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for ATC/TTC and CBM/TRM. The proposed "Modification to MOD-001-0 Documentation of ATC and TTC Calculation" SAR and "Modification to standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 SAR are the culmination[1] of the LTATF's work and is the subject matter for this Comment Form.

The SAC and the LTATF would like to receive industry comments on the scope and need for these two individual SARs. Accordingly, we request your comments included on this form, emailed to sarcomm@nerc.com with the subject "ATC/TTC/CBM/TRM Comments" by **August 7, 2005**.

## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
| | | R1.9 | Add/Delete Language |
| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

**1. Is there a reliability need for the proposed standard?**

☒ Yes

☒ No

Comments: Yes for TTC: TTCs reflect the operating/planning system conditions thus have to be accurate to achieve system reliability

No for ATC/AFC : ATCs/AFCs are quantities that are based on different market rules to access the transmission systems and to manage system congestion. Thus ATC and AFC should be market driven

**2. Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

☒ Yes

☐ No

Comments: The proposed standard is already going too much into methodology details

**3. Do you agree with the scope of the proposed standard?**

☒ Yes

☒ No

Comments: the standard should be limited to TTC/TFC for reliability purposes and ATC/AFC should addressed by NAESB

**4. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☒ Yes

☐ No

Comments: System quantities that are required by the market (such as ATC/AFC ) should be defined by NAESB

**5. Do you agree with the list of entities to which the standard would apply?**

☐ Yes

☒ No

Comments: LSE, PSE, MO, PA, TP

**6. Do you have any other terms that should be included in the definitions?**

☒ Yes

☒ No

Comments:

- NATC and RATC .firm or non firm should be defined by NAESB

- ultimate source and sink have a role in TTC determination and should be included in the NERC standard

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes

☒ No

Comments: The proposed standard is already too much directive and may unduly impose some coordination requirements to some transmission service providers

**8. Do you have any other comments on these proposed standards?**

Comments: The proposed standard is asking for exhaustive coordination in TTC/ATC/AFC calculation. Outside system boundary coordination requirements are needed in some parts of an Interconnection but could be minimal in other parts. For example, such exhaustive coordination is not required for DC transmission facilities between two asynchronous system.

Hydro-Québec TransÉnergie believes that although standardization and coordination of the calculation of ATC, AFC, TTC and the related definitions of TRM and CBM is a valuable goal, it must take into account the specifics of each System. In its own particular case, Hydro-Québec TransÉnergie's system is in fact a distinct Interconenction as it is not synchronized with the Eastern Interconnection. Its ties with the Eastern Interconnection are either controllable (DC ties) or radial (generation/load pockets isolated from one system and synchronized with the other). This situation must be taken into account when calculating TTC and ATC.

Not being subject to loop flows originating from neighboring Systems and its internal dispatch causing no such loop flows on those Systems, Hydro-Québec TransÉnergie does not have to participate in coordination to calculate flowgate capacities (AFC). Hydro-Québec TransÉnergie already posts its calculation methodology for ATC on its OASIS. The drafting team should include such considerations in the preparation of the releveant standards.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☒ Yes

☒ No

Comments: Yes for the TRM use to take into account inaccuracy/uncertainty in TTCs forcasted values. No for the CBM and the TRM use to retain transmission capacity for unplanned utilisation. System reliability impacted by transmission congestion could be managed by the market through adequate and well coordonated market rules. LSEs should gain firm access to the system to be protected for contingencies by acquiring adequate transmissiion service from the source to the load, not by CBM and/or TRM.

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☐ Yes

☒ No

Comments: LSEs should gain firm access to the system to be protected for contingencies by acquiring adequate transmissiion service from the source to the load, not by CBM and/or TRM.

**11. Do you agree with the scope of the proposed standard?**

☒ Yes

☒ No

Comments: see 9. in addition over utilisation of TRM and CBM may lead to limit open access to the system

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☒ Yes

☐ No

Comments: System reliability impacted by transmission congestion could be manage by the market through adequate and well coordonate market rules

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes
☒ No

Comments: LSE, PSE, MO, PA, TP

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes
☒ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes
☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments: The proposed standard is asking for exhaustive coordination in TRM calculation. Outside system boundary coordination requirements are needed in some parts of an Interconnection but could be minimal in other parts. For example, such exhaustive coordination is not required for DC transmission facilities between two asynchronous system.

## SAR Comment Form
## Proposed Revisions to Existing Standard Number MOD-001-0
## and
## Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

This form is to be used to submit comments on Draft 1 of two individual SARs: 1) Proposed Revisions to Existing Standard Number MOD-001-0 dealing with AFC/ATC/TTC; and 2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 dealing with CBM/TRM. Comments must be submitted by **August 08, 2005**. You may submit the completed form by emailing it to: sarcomm@nerc.com with the words "ATC/TTC/CBM/TRM Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

**ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE AND IT IS THEREFORE IMPORTANT TO ADHERE TO THE FOLLOWING REQUIREMENTS:**

**DO:** **Do** enter text only, with no formatting or styles added.
**Do** use punctuation and capitalization as needed (except quotations).
**Do** use more than one form if responses do not fit in the spaces provided.
**Do** submit any formatted text or markups in a separate WORD file.

**DO NOT:** **Do not** insert tabs or paragraph returns in any data field.
**Do not** use numbering or bullets in any data field.
**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Ron Falsetti | |
| Organization: | Ontario - Independent Electricity System Operator | |
| Telephone: | 905-855-6187 | |
| Email: | ron.falsetti@ieso.ca | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☒ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☐ | 4 - Transmission-dependent Utilities |
| ☐ MAIN | ☐ | 5 - Electric Generators |
| ☐ MAPP | ☐ | 6 - Electricity Brokers, Aggregators, and Marketers |
| ☒ NPCC | ☐ | 7 - Large Electricity End Users |
| ☐ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact Email:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information:

The Long-Term AFC/ATC Task Force (LTATF) was formed to develop specific recommendations for the calculation and coordination of AFC/ATC with the goal of increasing market liquidity and enhancing grid reliability. The task force's work was coordinated with NAESB to separate business practices from reliability concerns. The LTATF evaluated the results of the short-term recommendations in the Alliant West area for summer 2004, and used this evaluation when considering whether to recommend the Alliant West short-term recommendations continue.

In developing their recommendations the LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for ATC/TTC and CBM/TRM. The proposed "Modification to MOD-001-0 Documentation of ATC and TTC Calculation" SAR and "Modification to standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 SAR are the culmination[1] of the LTATF's work and is the subject matter for this Comment Form.

The SAC and the LTATF would like to receive industry comments on the scope and need for these two individual SARs. Accordingly, we request your comments included on this form, emailed to sarcomm@nerc.com with the subject "ATC/TTC/CBM/TRM Comments" by **August 7, 2005**.

## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
| | | R1.9 | Add/Delete Language |
| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

**1. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments:

**2. Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

☒ Yes

☒ No

Comments: IESO agrees that the proposed scope of the standard is sufficient to address reliability concerns. IESO disagrees that there needs to be a standard method for calculation of ATC, AFC and TTC for all ISOs/RTOs. Some differences in methodologies (market, non-market, etc.) may exist, but the processes must be coordinated and work together.

**3. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments: See comments above.

**4. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**5. Do you agree with the list of entities to which the standard would apply?**

☐ Yes

☒ No

Comments: Aspects of this standard would also apply to Transmission Planner, Transmission Owner, Planning Authority, RC and Regional Reliability Organization.

**6. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes

☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments:
IESO would suggest the following replace all of R1, not just the first paragraph:
"The development of TTC/ATC/AFC methodology is primarily the responsibility of the Transmission Provider, but may be delegated to a Balancing Authority, a Reliability Coordinator. All responsible entities shall develop and document a TTC and ATC/AFC methodology. In the case where the methodology is developed by a designated entity, that methodology document must clearly indicate to which Transmission Providers it applies. That methodology shall be reviewed by the RRO to ensure coordination between the entities within that region and to ensure compliance with this standard. This methodology document shall be available to NERC, the Regions, and the stakeholders in the electricity market."
With this change, the language in R1.12 is no longer required.

R1.7 - Several items in the set may be considered confidential information that should not be shared with market participants (such as generator outages and generator dispatch orders). These items can be shared with Transmission Service Providers to be used in TTC and ATC calculations but not be released to market participants.

R1.7.2 - Because of variations on how generation is dispatched in different markets, the drafting team will need to be clear on the generator dispatch information being requested and how it will be used.

R1.7.2 - For generators that will be used to determine firm AFC, these should be limited to generators that have already secured firm usage of the transmission system. A transmission service provider should not include generators in the firm AFC calculation that do not have firm transmission service backing them up.

R1.7.6 - The IESO does not believe a NERC standard should reference a specific tool (such as the SDX). It should be more general and apply to the current tool(s)?

R1.7.7 - IESO doesn't understand why AFC will be exchanged only between entities that have coordination agreements. In the Monitoring/Coordination Section of the LTATF Final Report, it states "The Task Force recommends the revision of the existing NERC standards to require the recognition and respect of impacts on external flowgates/paths in AFC/ATC calculations, and the establishment of NERC standards on AFC/ATC coordination." Monitoring other party flowgates was recommendation V. in the AWTTF Short-Term Recommendations.

R1.9 - The assumption should also include treatment of transmission requests with a status of Study (for both the transmission provider requests and neighboring transmission provider requests) and long-term firm reservations with roll-over rights (for both the transmission provider requests and neighboring transmission provider requests).

General - The concepts in Appendix will need to be considered in development of the standard. It contains ATC and AFC formula that are not stated in the body of the SAR.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments:

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes

☐ No

Comments: Some areas use zero for CBM. If CBM is used, the standardized definitions should be used and amount disclosed.

**11. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments:

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes

☒ No

Comments: Aspects of this standard should also apply to Transmission Planner, Transmission Owner, Planning Authority, RC and Regional Reliability Organization

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes

☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments:

COMMENTS TO MOD-004-0 and MOD-008-0

R1 - References to having a single regional CBM methodology and TRM methodology should be removed along with references to exceptions for entities that are members of an RTO or an ISO.

R.1.6 - To the extent generators that are not committed to serve load inside the transmission provider's system are considered in the CBM requirement determination, there should be CBM preserved on impacted flowgates for the use of this generation.

Please note the numbering error. There are two R1.4, R1.5 and R1.6.

R1.8 - CBM should not be used in place of maintaining either minimum planning reserves or to compensate for poor generator maintenance practices.

General - When establishing CBM import area boundaries, there is an explicit assumption that all generators can serve all load within the boundary (with no constraints). As part of the description of the CBM calculation process, it should describe the basis for establishing the CBM import area boundaries.

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
**and**
**Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0**

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**DO NOT:** **Do not** insert tabs or paragraph returns in any data field.
**Do not** use numbering or bullets in any data field.
**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Kathleen M. Goodman |
| Organization: | ISO New England |
| Telephone: | (413) 535-4111 |
| Email: | kgoodman@iso-ne.com |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☒ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☐ | 4 - Transmission-dependent Utilities |
| ☐ MAIN | ☐ | 5 - Electric Generators |
| ☐ MAPP | ☐ | 6 - Electricity Brokers, Aggregators, and Marketers |
| ☒ NPCC | ☐ | 7 - Large Electricity End Users |
| ☐ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact Email:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information:

The Long-Term AFC/ATC Task Force (LTATF) was formed to develop specific recommendations for the calculation and coordination of AFC/ATC with the goal of increasing market liquidity and enhancing grid reliability. The task force's work was coordinated with NAESB to separate business practices from reliability concerns. The LTATF evaluated the results of the short-term recommendations in the Alliant West area for summer 2004, and used this evaluation when considering whether to recommend the Alliant West short-term recommendations continue.

In developing their recommendations the LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for ATC/TTC and CBM/TRM. The proposed "Modification to MOD-001-0 Documentation of ATC and TTC Calculation" SAR and "Modification to standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 SAR are the culmination[1] of the LTATF's work and is the subject matter for this Comment Form.

The SAC and the LTATF would like to receive industry comments on the scope and need for these two individual SARs. Accordingly, we request your comments included on this form, emailed to sarcomm@nerc.com with the subject "ATC/TTC/CBM/TRM Comments" by **August 7, 2005**.

## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
| | | R1.9 | Add/Delete Language |
| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

1. **Is there a reliability need for the proposed standard?**

   ☒ Yes

   ☐ No

   Comments:

2. **Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

   ☒ Yes

   ☐ No

   Comments:

3. **Do you agree with the scope of the proposed standard?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

   **Note: NAESB has a proposal for companion business practice - R05004)**

   ☐ Yes

   ☒ No

   Comments:

5. **Do you agree with the list of entities to which the standard would apply?**

   ☐ Yes

   ☒ No

   Comments: Aspects of this standard will also apply to Transmission Planner and Regional Reliability Organization

**6. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes

☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments:

Comments on the proposed wording:

- The current wording of R1 is very confusing, and does not require that RTO/ISOs have a documented methodology. It seems to be trying to acknowledge that some TPs within an RRO may be using an RTO/ISO methdology. We would recommend that while there may be more than one methodology applicable in a region, it should be required that the methdology for every TP in the RRO be available on the RRO website.
- R3 is duplicative and should be deleted
- We do not understand why Generation Dispatch orders are required for TTC/ATC coordination, Generation Outage coordination should be adequate
- It is unclear in the SAR what the intent is of the Appendix. We do not support the definitions shown being included in the standard.

Recommendation for a Regional Difference:

We suggest that a Regional Difference be added to acknowledge that for TPs within a purely financial market, the ATC requirements of this standard are not applicable. However, the requirements associated with TTC continue to be applicable to these TPs. In addition, if these TPs do post ATC, they should be required to post the methodology used to calculate those posted values.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☒ Yes
☐ No

Comments:

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes
☐ No

Comments: While not all TPs use CBM, those that do use it for reliability reasons.

**11. Do you agree with the scope of the proposed standard?**

☒ Yes
☐ No

Comments:

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes
☒ No

Comments:

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes
☒ No

Comments: Aspects of this standard will also apply to Transmission Planner and Regional Reliability Organization

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes

☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments: Comments on the proposed wording:

- R1 of MOD-004 and MOD-008 are confusing and do not require an ISO/RTO to post their methodology. While there may be more than one methodology applicable in a region, it should be required that the methdology for every TP in the RRO be available on the RRO website
- R1.8.1 MOD-008 implies that TRM is set as a fixed amount which must be maintained through time, since entities would be required to "plan and reinforce the transmission system for the amount of TRM being preserved". We feel that this is an inappropriate requirement, since TRM represents a variable quantity based on known system conditions plus uncertainty.
- R1.8.2 of MOD-008 is not related to item 1.8 and should be moved in the text to be before and applicable to all R1.x requirements.

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
**and**
**Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0**

This form is to be used to submit comments on Draft 1 of two individual SARs: 1) Proposed Revisions to Existing Standard Number MOD-001-0 dealing with AFC/ATC/TTC; and 2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 dealing with CBM/TRM. Comments must be submitted by **August 08, 2005**. You may submit the completed form by emailing it to: sarcomm@nerc.com with the words "ATC/TTC/CBM/TRM Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

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**DO:** **Do** enter text only, with no formatting or styles added.
**Do** use punctuation and capitalization as needed (except quotations).
**Do** use more than one form if responses do not fit in the spaces provided.
**Do** submit any formatted text or markups in a separate WORD file.

**DO NOT:** **Do not** insert tabs or paragraph returns in any data field.
**Do not** use numbering or bullets in any data field.
**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| Email: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☐ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☐ | 4 - Transmission-dependent Utilities |
| ☐ MAIN | ☐ | 5 - Electric Generators |
| ☐ MAPP | ☐ | 6 - Electricity Brokers, Aggregators, and Marketers |
| ☐ NPCC | ☐ | 7 - Large Electricity End Users |
| ☐ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** RTO/ISO Standards Review Committee

**Lead Contact:** **Karl Tammar**

**Contact Organization:** **NYISO**

**Contact Segment:** **2**

**Contact Telephone:** **518-356-6205**

**Contact Email:** **ktammar@nyiso.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| **Anita Lee** | **AESO** | | **2** |
| **William Phillips** | **MISO** | | **2** |
| **Sam Jones** | **ERCOT** | | **2** |
| **Ron Falsetti** | **IESO** | | **2** |
| **Peter Brandien** | **ISO-NE** | | **2** |
| **Karl Tammar** | **NYISO** | | **2** |
| **Bruce Balmat** | **PJM** | | **2** |
| **Charles Yeung** | **SPP** | | **2** |
| **Lisa Szot** | **CAISO** | | **2** |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information:

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## Tabular Summary of Requirement Changes

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|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
| | | R1.9 | Add/Delete Language |
| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

**1. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments:

**2. Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

☒ Yes

☒ No

Comments: We agree that the proposed scope of the standard is sufficient to address relaibility concerns. We disagree that there needs to be a standard method for calulation of ATC, AFC and TTC for all ISOs/RTOs. Some differences in methodologies (market, non-market, etc.) may exist, but the processes must be coordinated and work together.

**3. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments: See comments above.

**4. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**5. Do you agree with the list of entities to which the standard would apply?**

☐ Yes

☒ No

Comments: Aspects of this standard would also apply to Transmission Planner, Transmission Owner, Planning Authority, RC and Regional Reliability Organization.

**6. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes

☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments:
We would suggest the following replace all of R1, not just the first paragraph:
"The development of TTC/ATC/AFC methodology is primarily the responsibility of the Transmission Provider, but may be delegated to a Balancing Authority, a Reliability Coordinator. All responsible entities shall develop and document a TTC and ATC/AFC methodology. In the case where the methodology is developed by a designated entity, that methodology document must clearly indicate to which Transmission Providers it applies. That methodology shall be reviewed by the RRO to ensure coordination between the entities within that region and to ensure compliance with this standard. This methodology document shall be available to NERC, the Regions, and the stakeholders in the electricity market."
With this change, the language in R1.12 is no longer needed.

R1.7 - Several items in the set may be considered confidential information that should not be shared with market participants (such as generator outages and generator dispatch orders). These items can be shared with Transmission Service Providers to be used in TTC and ATC calculations but not be released to market participants.

R1.7.2 - Because of variations on how generation is dispatched in different markets, the drafting team will need to be clear on the generator dispatch information being requested and how it will be used.

R1.7.2 - For generators that will be used to determine firm AFC, these should be limited to generators that have already secured firm usage of the transmission system. A transmission service provider should not include generators in the firm AFC calculation that do not have firm transmission service backing them up.

R1.7.6 - Should a NERC standard reference a tool (such as the SDX) or be more general and apply to the current tool?

R1.7.7 - We don't understand why AFC will be exchanged only between entities that have coordination agreements. In the Monitoring/Coordination Section of the LTATF Final Report, it states "The Task Force recommends the revision of the existing NERC standards to require the recognition and respect of impacts on external flowgates/paths in AFC/ATC calculations, and the establishment of NERC standards on AFC/ATC coordination." Monitoring other party flowgates was recommendation V. in the AWTTF Short-Term Recommendations.

R1.9 - The assumption should also include treatment of transmission requests with a status of Study (for both the transmission provider requests and neighboring transmission provider requests) and long-term firm reservations with roll-over rights (for both the transmission provider requests and neighboring transmission provider requests).

General - The concepts in Apendix will need to be considered in development of the standard. It contains ATC and AFC formula that are not stated in the body of the SAR.

## CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments:

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes

☐ No

Comments: Some areas use zero for CBM. If CBM is used, the standardized definitions should be used and amount disclosed.

**11. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments:

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes

☒ No

Comments: Aspects of this standard should also apply to Transmission Planner, Transmission Owner, Planning Authority, RC and Regional Reliability Organization

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes

☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments:

COMMENTS TO MOD-004-0 and MOD-008-0

R1 - References to having a single regional CBM methodology and TRM methodology should be removed along with references to exceptions for entities that are members of an RTO or an ISO.

R.1.6 - To the extent generators that are not committed to serve load inside the transmission provider's system are considered in the CBM requirement determination, there should be CBM preserved on impacted flowgates for the use of this generation.

There are two R1.4, R1.5 and R1.6.

R1.8 - CBM should not be used in place of maintaining either minimum planning reserves or to compensate for poor generator maintenance practices.

General - When establishing CBM import area boundaries, there is an explicit assumption that all generators can serve all load within the boundary (with no constraints). As part of the description of the CBM calculation process, it should describe the basis for establishing the CBM import area boundaries.

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| Email: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☐ | 2 - RTOs, ISOs, Regional Reliability Councils |
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| ☐ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** Medwest Reliability Organization

**Lead Contact:** **Ken Goldsmith**

**Contact Organization:** **MRO**

**Contact Segment:** **2**

**Contact Telephone:** **319-786-4167**

**Contact Email:** **kengoldsmith@alliantenergy.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Al Boesch | NPPD | MRO | 2 |
| Terry Bilke | MISO | MRO | 2 |
| Robert Coish | MHEB | MRO | 2 |
| Dennis Florom | LES | MRO | 2 |
| Todd Gosnell | OPPD | MRO | 2 |
| Wayne Guttormson | SPC | MRO | 2 |
| Jim Maenner | WPS | MRO | 2 |
| Tom Mielnik | MEC | MRO | 2 |
| Darrick Moe | WAPA | MRO | 2 |
| Joe Knight | MRO | MRO | 2 |
| The 31 Additional MRO Member | Companies not named above | MRO | 2 |
| with the exception of Alliant | Energy, which does not agree | MRO | 2 |
| with the comments as | presented. | | |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information:

The Long-Term AFC/ATC Task Force (LTATF) was formed to develop specific recommendations for the calculation and coordination of AFC/ATC with the goal of increasing market liquidity and enhancing grid reliability. The task force's work was coordinated with NAESB to separate business practices from reliability concerns. The LTATF evaluated the results of the short-term recommendations in the Alliant West area for summer 2004, and used this evaluation when considering whether to recommend the Alliant West short-term recommendations continue.

In developing their recommendations the LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for ATC/TTC and CBM/TRM. The proposed "Modification to MOD-001-0 Documentation of ATC and TTC Calculation" SAR and "Modification to standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 SAR are the culmination[1] of the LTATF's work and is the subject matter for this Comment Form.

The SAC and the LTATF would like to receive industry comments on the scope and need for these two individual SARs. Accordingly, we request your comments included on this form, emailed to sarcomm@nerc.com with the subject "ATC/TTC/CBM/TRM Comments" by **August 7, 2005**.

## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
| | | R1.9 | Add/Delete Language |
| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

1. **Is there a reliability need for the proposed standard?**

   ☒ Yes

   ☐ No

   Comments:

2. **Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

   ☒ Yes

   ☐ No

   Comments:

3. **Do you agree with the scope of the proposed standard?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

   **Note: NAESB has a proposal for companion business practice - R05004)**

   ☐ Yes

   ☒ No

   Comments: There may be certain practices that could be considered for a NAESB Business Practice, however compliance with it should be voluntary

5. **Do you agree with the list of entities to which the standard would apply?**

   ☐ Yes

   ☒ No

Comments: Aspects of this standard should also apply to Transmission Planner, Transmission Owner, Planning Authority and Regional Reliability Organization.

**6. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes

☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments: On page SAR - 4 Clarification is needed providing the direction for the Standard Drafting Team concerning definitions. This portion of the SAR is not written in complete sentences so that it can be completely understood by those who are not on the LTATF For example, the SAR lists "Daily, Monthly, Yearly TTC". Does the LTATF wish the Standard Drafting Team to prepare definitions for Daily, Monthly, Yearly TTC? The SAR says that the TTC and ATC are defined in standard 1E1. These definitions should be repeated here so that it is clear what the SDT should use as a starting point. ATC is defined in the SAR by an equation. Is this to be added to the definition in 1E1 for ATC or is this already included in the previous definition? Then ATC is listed with no directions. Does the LTATF wish ATC to be defined, ATC definition to change, or something else? The SAR needs to be specific as to which definitions the SAR drafting team thinks needs to be added, deleted, or changed. If changes are needed, the SAR needs to explain what sort of changes are required.

COMMENTS TO MOD-001-0

R1 - Revise the first paragraph to read " Each Transmission Provider shall develop and document a TTC and ATC (may include the calculation of AFC) methodology, and require coordination between the

Transmission Providers, with oversight by the respective RRO's." We do not see the need for a RRO region wide methodology, but do see the need for the RRO to review the methodology the Transmission Providers use to insure it meets the requirements of this standard. The regional methodology would need to be at a high level even with the exclusion of RTO/ISO members. MRO members include ISO and non-ISO members throughout the MRO region. It would be better for reliability to have the MRO review the Transmission Provider methodology for the items included in the standard then to have a high level regional methodology for non-ISO/RTO members.

R1.1 - Revise the first sentence to read "Include a narrative explaining how TTC and ATC values are determined and how those values are used in evaluating a transmission service request (TSR), and how the results of the TSR evaluation are made available to customers."

R1.2 - Please clarify what the explanation in the second sentence is meant to accomplish.

R1.71 - We would recommend revising the 13 month time frame to 12 months, to reflect seams agreements presently in place.

R1.7.2 - The update frequency should at least be seasonal.

R1.7.3 - We would recommend revising the 13 month time frame to 12 months, to reflect seams agreements presently in place.

R1.9 - Add "(Netting)" after "Transmission Reservations".

R1.12 - Revise the article to have the RRO provide authorization for a variance to the regionally approved Transmission Provider's ATC/TTC methodology. Variances to the MRO approval do not require NERC approval.

R3 should be combined with R1.1

Section C. Measures should be as follows:
M1. Each group of transmission service providers within a region, in counjunction with the members of that region, shall jointly develop and implement a procedure to review changes periodically (at least annually) and ensure that that TTC and ATC/AFC calculations and resulting values of member transmission providers

comply with the Regionally approved Transmission Provider TTC and ATC methodology, the NERC Planning Standards, and applicable RRO criteria.

M2. A review to verify that theAFC/TTC calculations are consistent with the TO's/TP's planning criteria is also required. The procedure used to verify the consistency must also be documented in the report. Documentation of the results of the most current reviews shall be provided to NERC within 30 days of compliance.

M3. Each entity responsible for the TTC and ATC methodology, in conjunction with its member(s) and stakeholders, shall have and document a procedure on how stakeholders can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission provider(s), and how these concerns or questions will be addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the stakeholders in the electricity market.

M4. The RRO must review and approve the ATC/TTC methodology so as to ensure it is consistent with the RRO's Planning and Operating Criteria.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments:

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes

☐ No

Comments: Some Reserve Sharing Pools utilize CBM to insure transfer capability is available for movement of energency energy. Without CBM, this may not be possible resulting in significant reliability issues.

**11. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments:

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments: There may be certain practices that could be considered for a NAESB Business Practice, however compliance with it should be voluntary.

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes

☒ No

Comments: Aspects of this standard should also apply to Transmission Planner, Transmission Owner, Planning Authority and Regional Reliability Organization

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes

☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments: COMMENTS TO MOD-004-0

R1 - Revise the first paragraph to read " Each Transmission Provider shall develop and document a CBM methodology, and require coordination between the transmission providers, with oversight by the respective RRO's."  We do not see the need for a RRO region wide methodology, but do see the need for the RRO to review the methodology the Transmission Providers use to insure it meets the requirements of this standard.  The regional methodology would need to be at a high level even with the exclusion of RTO/ISO members.  For example the MRO members include ISO and non-ISO members throughout the MRO region. It would be better for reliability to have the MRO review the Transmission Provider methodology for the items included in the standard than to have high-level regional methodology for non-ISO/RTO members.

R1.2 - In bullets 1 and 2 the word "must" should be deleted.  It is not necessary.

The article numbering after R1.6 is in error.  It drops back to R1.4, when it should be R1.7.

Under present article number R1.4, Revise the first sentence to "Describe the formal process and rationale for the RRO to grant any variances to an individual transmission provider's regionally approved CBM Methodology." R1.6.1 should be deleted. The RRO approves variances.

Under the present article number R1.7 - Clarify what the objective is for the "simultaneous application of CBM and TRM." Is this intended to make sure that reserves are not double counted?

It is not stated if Measures M1 and M2 are kept or not. Please confirm that they are still in force.

COMMENTS TO MOD-005-0

R1 - Revise the first sentence to read "Each RRO in conjunction with its members, shall develop and implement a procedure to review changes (at least annually) to the CBM calculations and the resulting values of member Transmission Service Providers."

R1.3 - We believe R1.3.1 should be incorporated into the standard.

COMMENTS TO MOD-006-0

We are not opposed to making this standard a Busniess Practice, as long as the Business Practice is voluntary.

COMMENTS TO MOD-008-0

R1 - Revise the first sentence of the paragraph to read " Each Transmission Provider in a region shall develop and document, in conjunction with the members of the region, a TRM methodology, and require coordination between the transmission providers, with oversight by the respective RRO's." We do not see the need for a RRO region wide methodology, but do see the need for the RRO to review the methodology the Transmission Providers use to insure it meets the requirements of this standard. The regional methodology would need to be at a high level even with the exclusion of RTO/ISO members. For example the MRO members include ISO and non-ISO members throughout the MRO region. It would be better for reliability to have the MRO review the Transmission Provider methodology for the items included in the standard than to have high-level regional methodology for non-ISO/RTO members.

R1.3.10 should be renumbered to R1.3.9. The article that was numbered R1.3.9 should be placed at the end of the list and not have a number.

R1.5 - Revise the first sentence to "Describe the formal process and rationale for the RRO to grant any variances to an individual transmission provider's regionally approved TRM Methodology." R1.5.1 should be deleted. The RRO approves variances.

R1.7 - Clarify what the objective is for the "simultaneous application of CBM and TRM." Is this intended to make sure that reserves are not double counted?

COMMENTS TO MOD-009-0

R1 - Revise the first sentence of the paragraph to read " The RRO in a region shall develop and document, in conjunction with the members of the region, a procedure to, at least annually, review the TRM calculations and the resulting values of member transmission providers, to ensure that they comply with the regionally approved transmission provider methodologies." We do not see the need for a RRO region wide methodology, but do see the need for a region-wide process to review the methodology the Transmission Providers use to insure it meets the requirements of this standard. The regional methodology would need to be a high level even with the exclusion of RTO/ISO members. For example the MRO members include ISO and non-ISO members throughout the MRO region. It would be better for reliability to have the MRO review the Transmission Provide methodology for the items included in the standard than to have high-level regional methodology for non-ISO/RTO members.

R1.1 - Change the article to ". . . implemented, and made available to the RRO's, NERC, and stakeholders."

R1.4 - Combine this article into R1.3.

R4 - Delete as it is included in the revised R1.1.

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
**and**
**Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0**

This form is to be used to submit comments on Draft 1 of two individual SARs: 1) Proposed Revisions to Existing Standard Number MOD-001-0 dealing with AFC/ATC/TTC; and 2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 dealing with CBM/TRM. Comments must be submitted by **August 08, 2005**. You may submit the completed form by emailing it to: sarcomm@nerc.com with the words "ATC/TTC/CBM/TRM Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

**ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE AND IT IS THEREFORE IMPORTANT TO ADHERE TO THE FOLLOWING REQUIREMENTS:**

**DO:** **Do** enter text only, with no formatting or styles added.
**Do** use punctuation and capitalization as needed (except quotations).
**Do** use more than one form if responses do not fit in the spaces provided.
**Do** submit any formatted text or markups in a separate WORD file.

**DO NOT:** **Do not** insert tabs or paragraph returns in any data field.
**Do not** use numbering or bullets in any data field.
**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Matt Schull |
| Organization: | North Carolina Municipal Power Agency Number 1 |
| Telephone: | 919-760-6312 |
| Email: | mschull@electricities.org |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☐ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☐ | 4 - Transmission-dependent Utilities |
| ☐ MAIN | ☒ | 5 - Electric Generators |
| ☐ MAPP | ☐ | 6 - Electricity Brokers, Aggregators, and Marketers |
| ☐ NPCC | ☐ | 7 - Large Electricity End Users |
| ☒ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact Email:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information:

The Long-Term AFC/ATC Task Force (LTATF) was formed to develop specific recommendations for the calculation and coordination of AFC/ATC with the goal of increasing market liquidity and enhancing grid reliability. The task force's work was coordinated with NAESB to separate business practices from reliability concerns. The LTATF evaluated the results of the short-term recommendations in the Alliant West area for summer 2004, and used this evaluation when considering whether to recommend the Alliant West short-term recommendations continue.

In developing their recommendations the LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for ATC/TTC and CBM/TRM. The proposed "Modification to MOD-001-0 Documentation of ATC and TTC Calculation" SAR and "Modification to standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 SAR are the culmination[1] of the LTATF's work and is the subject matter for this Comment Form.

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## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
| | | R1.9 | Add/Delete Language |
| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

**1. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments:

**2. Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

☐ Yes

☒ No

Comments: ATC/TTC/AFC calculations should be standardized across all regions. The way the SAR is written now, TSPs within a region will be required to coordinate methodology and calculations, but the regions will not be required to coordinate with each other. Without standardized calcuations and coordination between regions, we will continue to have differences in regional ATC/TTC/AFC values and limit commercial activity. Rather than having calculation differences between neighboring TSPs as it is today, it will just be pushed up to the regional level and the problem of uncoordinated ATC/TTC/AFC values will remain.

**3. Do you agree with the scope of the proposed standard?**

☐ Yes

☒ No

Comments: The scope should include standardized ATC/TTC/AFC calculations and required coordination between regions.

**4. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**5. Do you agree with the list of entities to which the standard would apply?**

☒ Yes
☐ No

Comments:

**6. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes
☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments:

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☐ Yes
☐ No
Comments:

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☐ Yes
☐ No
Comments:

**11. Do you agree with the scope of the proposed standard?**

☐ Yes
☐ No
Comments:

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes
☐ No
Comments:

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes
☐ No
Comments:

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes

☐ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes

☐ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments:

# SAR Comment Form
# Proposed Revisions to Existing Standard Number MOD-001-0
# and
# Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

This form is to be used to submit comments on Draft 1 of two individual SARs: 1) Proposed Revisions to Existing Standard Number MOD-001-0 dealing with AFC/ATC/TTC; and 2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 dealing with CBM/TRM. Comments must be submitted by **August 08, 2005**. You may submit the completed form by emailing it to: sarcomm@nerc.com with the words "ATC/TTC/CBM/TRM Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

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- **Do** use punctuation and capitalization as needed (except quotations).
- **Do** use more than one form if responses do not fit in the spaces provided.
- **Do** submit any formatted text or markups in a separate WORD file.

**DO NOT:**
- **Do not** insert tabs or paragraph returns in any data field.
- **Do not** use numbering or bullets in any data field.
- **Do not** use quotation marks in any data field.
- **Do not** submit a response in an unprotected copy of this form.

**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Paul B. Johnson |
| Organization: | Chairman, ATC Task Force of NERC Planning Committee |
| Telephone: | 614-552-1670 |
| Email: | pbjohnson@aep.com |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☐ | 2 - RTOs, ISOs, Regional Reliability Councils |
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| X ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** **ATC Task Force of NERC Planning Committee**

**Lead Contact:** **Paul B. Johnson, Chairman**

**Contact Organization:** **American Electric Power**

**Contact Segment:** **RRO**

**Contact Telephone:** **614-552-1670**

**Contact Email:** **pbjohnson@aep.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| **Thomas C. Mielnik** | **MidAmerican Energy Co.** | **MRO** | **RRO** |
| **William Harm** | **PJM Interconnection** | **MAAC** | **RRO** |
| **Ronald F. Szymczak** | **Exelon Corporation** | **MAIN** | **RRO** |
| **Thomas E. Washburn** | **Orlando Utilities Commission** | **FRCC** | **RRO** |
| **Lee Westbrook** | **TXU Electric Delivery** | **ERCOT** | **RRO** |
| **Virginia C. Sulzberger** | **NERC** | ___ | ___ |
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The SAC and the LTATF would like to receive industry comments on the scope and need for these two individual SARs. Accordingly, we request your comments included on this form, emailed to sarcomm@nerc.com with the subject "ATC/TTC/CBM/TRM Comments" by **August 7, 2005**.

## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
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| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
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| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

**1. Is there a reliability need for the proposed standard?**

X Yes

☐ No

Comments: Yes – It is important to recognize that while AFC/ATC/TTC are not indicators of reliability, AFC/ATC/TTC values are limited by NERC standards and definitions, Regional criteria, and the physical characteristics of the interconnected electric systems. The proper calculation and use of AFC/ATC/TTC are critical to maintaining system reliability.

**2. Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

☐ Yes

X No

Comments: No – The NERC Planning Committee encourages further standardization of certain key elements and parameters in the calculation of ATC, AFC, and TTC. The proposed standards on ATC, AFC, and TTC calculations must require that key elements of the calculation critical to reliability be incorporated into any proposed NERC ATC and TTC standard methodology and strengthened for increased consistency.

The existing NERC ATC and TTC methodology prescribes a set of requirements that must be addressed in calculating ATC and TTC values. While the current methodology provides a degree of commonality in the calculations, that commonality needs to be strengthened. This strengthening of the calculation requirements refers to additions and refinements to the elements or parameters to be addressed in the calculation methodology and not to the tools or equipment used for the calculations.

Some examples of the elements critical to reliability and for which further standardization in the ATC and TTC calculations should be required include: 1) coordination in the exchange and use of system data within the Regions and among adjacent Regions, 2) the monitoring of critical limiting transmission facilities under appropriate contingencies consistent with planning and operating criteria, 3) consistency in the manner in which transmission services are reserved, scheduled, and accounted in the calculations, 4) using appropriate generation dispatches, 5) meeting a minimum frequency of ATC and TTC calculations, 6) base case model building (i.e., what data needs to be incorporated and updated), 7) ATC and TTC calculators (those who are responsible for calculating ATC and TTC values) who impact each other's transmission system must have appropriate and adequate model representation (load level, generation dispatch, transmission and generation outages) of each other's system, and 8) monitoring of transmission facilities based on the use of an appropriate distribution cutoff factor.

Further, AFC (available flowgate capability) must be clearly defined. The NERC ATC and TTC methodology must be expanded to include and describe the key elements that must be addressed in the calculation of AFC values. In addition, the relationship of AFC to ATC and TTC must be clearly defined along with the manner in which they will be used and coordinated in accounting for transmission reservations and schedules.

3. **Do you agree with the scope of the proposed standard?**

☐ Yes

X No

Comments: No – Please see comments provided in response to Question 2.

4. **Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

X Yes

☐ No

Comments: Yes – The business process flow of requesting transmission service, the evaluation of a transmission service request against the calculated ATC, TTC, or AFC values, and the communication of the resulting service to the transmission user are possible elements to be considered in business practice standards. In developing the business practices, care must be taken to ensure that the tools or equipment to implement this process flow not be specified, only the process flow. All aspects dealing with reliability must be handled by NERC.

5. **Do you agree with the list of entities to which the standard would apply?**

☐ Yes

X No

Comments: No – Aspects of this standard also should apply to the Transmission Planner, Transmission Owner, Planning Authority, and Regional Reliability Organization.

In those areas where Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), or other agents, such as Transmission Service Coordinators (TSCs), are involved with ATC, TTC, and AFC calculations for multiple Regions or portions thereof, the role of these entities must be clearly defined.

6. **Do you have any other terms that should be included in the definitions?**

X Yes

☐ No

Comments: Yes – In the SAR or standard drafting of the proposed ATC/TTC standard, definitions must be established, as necessary, for industry acceptance so that a common language is used in reference to ATC and TTC. In particular, definitions for “flowgate,” “flowgate rating,” and “Available Flowgate Capability (AFC)” need to be established (See also the fourth paragraph in response to Question 2.) since these terms have never been formally defined by NERC.

On pages SAR - 4 and SAR – 9, further clarification and direction are needed for the Standard Drafting Team (SDT) concerning definitions. This portion of the SAR is not written in complete sentences and therefore may not be completely understood by those who were not on the LTATF. For example, the SAR lists “Daily, Monthly, Yearly TTC.” Does the LTATF wish the Standard Drafting Team to prepare definitions for Daily, Monthly, Yearly TTC and ATC? The SAR says that the TTC and ATC are defined in standard 1E1. These definitions should be repeated here so that it is clear what the SDT should use as a starting point. ATC is defined in the SAR by an equation. Is this to be added to the definition in 1E1 for ATC or is this already included in the previous definition? Then, Existing Transmission Commitments (ETC) is listed with no directions. Does the LTATF wish ETC to be defined, ETC definition to change, or something else? The SAR needs to be specific as to which definitions the SAR drafting team recommends to be added, deleted, or changed. If changes are needed, the SAR needs to explain what sorts of changes are required.

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes

X No

Comments: No additional data elements.

**8. Do you have any other comments on these proposed standards?**

Comments: Yes - The ATC/TTC SAR needs to be reworded to clearly establish the following:

1) A Regional ATC/TTC methodology must be developed in conjunction with Regional members.
2) All ATC/TTC calculators must abide by the Regional methodology for the Region in which they are members.
3) RTOs and ISOs that encompass multiple Regional Reliability Organizations are exempt from abiding by the Regional ATC/TTC methodology provided they have established a single ATC/TTC calculation methodology, in conjunction with their membership, for the entire RTO or ISO. These RTO or ISO methodologies must be consistent with the requirements of the NERC ATC/TTC standard and applicable Regional criteria.
4) RTOs and ISOs that are exempt from the Regional methodologies must perform reviews to ensure consistency between the RTO or ISO ATC /TCC calculation methodology and their members' transmission planning and operating criteria. If this requirement is not added, there is no check on the consistency with planning and operating criteria for members who are not under the Regional methodology but under an RTO or ISO ATC/TCC methodology. This requirement will help to ensure that ATC/TTC calculations only incorporate contingencies, TRM components, and CBM for which the systems are reinforced and planned.
5) Each RRO must review and approve the RTO or ISO ATC/TTC methodology to ensure that it is consistent with the NERC ATC/TTC standard and the RRO's planning and operating criteria. If this requirement is not added, there appears to be no check of an RTO or ISO's ATT/TCC methodology.

R1.1 – Revise the first sentence to read "Include a narrative explaining how TTC and ATC values are determined and how those values are used in evaluating a transmission service request (TSR), and how the results of the TSR evaluation are made available to customers."

R1.7.2 – The update frequency should at least be seasonal.

R3 – This requirement should be combined with R1.1.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

X Yes

☐ No

Comments: Yes - There is a reliability need for the CBM/TRM standard. Please see the comments provided in response to Question 10 below.

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

X Yes

☐ No

Comments: Yes – Earlier in the development of this industry, there were predominantly local, vertically integrated electric utilities. Each utility built sufficient generation to serve its own load responsibility. Transmission interconnections with neighboring utilities were typically established for one of the following reasons: 1) to minimize duplication of transmission (i.e., tie to neighbor for transmission reliability), and 2) an economic decision, to build transmission instead of generation based on the generation reliability criteria for which the utility planned (i.e., tie to neighbor to meet generation reliability criteria). This second reason is the origin of the CBM concept. Transmission interconnections provide each interconnected system with access to its neighbors so that in the event of an extreme generation outage within a utility, the temporarily generation deficient utility could have access to "emergency" generation resources from its interconnected neighbors. CBM is the quantification of this use of the transmission system. Therefore, CBM is an "emergency" use transmission quantity and only exists on the importing system for use only during periods of an emergency generation deficiency when firm transmission service is not available. Just as transmission capacity is preserved for the transmission contingencies for which a utility plans, transmission capacity is also preserved for the generation contingencies for which a utility plans. In either case, the utility customers paid for the transmission capacity that was installed to maintain the reliability level that is planned, via their rates for service.

Some reserve sharing pools utilize CBM to ensure transfer capability is available for movement of emergency energy. Without CBM, this may not be possible, resulting in significant reliability issues.

**11. Do you agree with the scope of the proposed standard?**

X Yes

☐ No

Comments: Yes – The scope of the standard is sufficient for the industry at this time.

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

X Yes

☐ No

Comments: Yes – The process under which CBM is used may be considered a business practice that could be handled by NAESB. However, the calculation of CBM amounts and how they are implemented in an ATC/TCC calculation are reliability issues that belong in the CBM/TRM standard.

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes

X No

Comments: No – Aspects of this standard also should apply to the Transmission Planner, Transmission Owner, Planning Authority, and Regional Reliability Organization.

In those areas where Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), or other agents, such as Transmission Service Coordinators (TSCs), are involved with ATC, TTC, and AFC calculations for multiple Regions or portions thereof, the role of these entities must be clearly defined.

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes

X No

Comments: No – In the SAR or standard drafting of the proposed CBM/TRM standard, definitions must be established, as necessary, for industry acceptance so that a common language is used in reference to CBM and TRM.

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes

X No

Comments: No additional data elements.

**16. Do you have any other comments on these proposed standards?**

Comments: Yes – The CBM/TRM SAR needs to be reworded to clearly establish the following:

1) A Regional CBM/TRM methodology must be developed in conjunction with Regional members.
2) All entities calculating CBM and/or TRM must abide by the Regional methodology for the Region in which they are members.
3) RTOs and ISOs that encompass multiple Regional Reliability Organizations are exempt from abiding by the Regional CBM/TRM methodologies provided they have established a single CBM and/or TRM calculation methodology, in conjunction with their membership, for the entire RTO or ISO. These RTO or ISO methodologies must be consistent with the requirements of the NERC CBM/TRM standard and applicable Regional criteria.
4) RTOs and ISOs that are exempt from the Regional methodologies must perform reviews to ensure consistency between the RTO or ISO CBM and/or TRM calculation methodologies and their members' transmission planning, generation planning, and operating criteria. If this requirement is not added, there is no check on the consistency with planning and operating criteria for members who are not under the Regional methodology but under an RTO or ISO CBM and/or TRM methodology.
5) In addition, the text in section R1 of the SAR needs to be revised to clarify that the following reviews are to be performed by the RRO. First, each RRO needs to review the CBM and/or TRM calculations of transmission providers under the Regional methodology to ensure they are adhering to the Regional methodology. Second, each RRO must review and approve the RTO and ISO CBM and/or TRM methodologies to ensure they are consistent with the NERC CBM/TRM standard and the RRO's planning and operating criteria. Finally, the RRO is responsible for ensuring that TRM calculations performed by transmission service providers, regardless of what methodology they are under, are consistent with the individual transmission owner's planning criteria.

COMMENTS TO MOD-004-0

R1.2 – In bullets 1 and 2, the word “must” should be deleted. It is not necessary.

Under the present article number R1.7 – Clarify what the objective is for the “simultaneous application of CBM and TRM.” Is this intended to make sure that reserves are not double counted?

COMMENTS TO MOD –008-0

R1.7 – Clarify what the objective is for the “simultaneous application of CBM and TRM.” Is this intended to make sure that reserves are not double counted?

COMMENTS TO MOD- 009-0

R1.4 – Combine this article into R1.3.

R4 – Delete, as it is included in the revised R1.1.

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**and**
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**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Guy V. Zito |
| Organization: | Northeast Power Coordinating Council |
| Telephone: | 212-840-1070 |
| Email: | gzito@npcc.org |

| NERC Region | | Registered Ballot Body Segment |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact Email:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

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|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
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| | | R1.4 | Add/Delete Language |
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1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

**1. Is there a reliability need for the proposed standard?**

☒ Yes

☒ No

Comments: TTC and TRM are reliability driven quanities however ATC/AFCs are quantities that are based on market rules and used in the managing of system congestion. ATC/AFC calculations are not required to achieve Reliability

**2. Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

☒ Yes

☐ No

Comments: Although it is agreed that the proposed scope is sufficient to address reliability objectives, we disagree that there needs to be a standard outlining the method for calculation of ATC/AFC. There are different market stuctures in the Northeast and the processes need to be coordinated to ensure they work together to achieve a transparent, documented methodology to calculate those quantities that are critical to maintaining reliability objectives.

**3. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments: See above comments

**4. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☒ Yes

☐ No

Comments: ATC/AFC system quantities that are market specific should be addressed by NAESB

**5. Do you agree with the list of entities to which the standard would apply?**

☐ Yes
☒ No

Comments: Aspects of this standard will also apply to Transmission Planner, Planning Authority and Regional Reliability Organization

**6. Do you have any other terms that should be included in the definitions?**

☒ Yes
☐ No

Comments: NATC and RATC should be defined by NAESB

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes
☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments:
General Comment: It must be noted that the application of ATC, and therefore its derivation, can be significantly different in market-based jurisdictions that do not take physical transmission reservations, and those that do. The principles that "An Organization Standard shall neither mandate nor prohibit any specific market structure" and "An Organization Standard shall not preclude market solutions to achieving compliance with that standard" must be maintained. The Standards Drafting Team must be familiar with the market structures in use in North America, to accommodate these variances

Items for the Standard Drafting team to consider with respect to the proposed wording:

- R1 is very confusing with it's reference to how the methodology must be documented. It seems to leave a hole that does not require RTO/ISOs to post their methodology. While there may be more than one methodology applicable in a region, it should be required that the methdology for every TP in the RRO be available on the RRO website.
- R3 is duplicative and should be deleted
- We do not understand why Generation Dispatch orders are required for TTC/ATC coordination, Generation Outage coordination should be adequate

- It is unclear in the SAR what the intent is of the Appendix. We do not support the definitions shown being included in the standard.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments:

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes

☐ No

Comments: While not all TPs use CBM, those that do use it for reliability reasons.

**11. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments:

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes

☒ No

Comments: Aspects of this standard will also apply to Transmission Planner, Planning Authority and Regional Reliability Organization

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes

☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments: Items for the Standard Drafting team to consider with respect to the proposed wording:

- R1 of MOD-004 and MOD-008 seem confusing and not to require an ISO/RTO to post their methodology. While there may be more than one methodology applicable in a region, it should be required that the methdology for every TP in the RRO be available on the RRO website
- R1.8.1 MOD-008 implies that TRM is set as a fixed amount which must be maintained through time, since entities would be required to "plan and reinforce the transmission system for the amount of TRM being preserved". We feel that this is an inappropriate requirement, since TRM represents a variable quantity based on known system conditions plus uncertainty.
- R1.8.2 of MOD-008 is not related to item 1.8 and should be moved in the text to be before and applicable to all R1.x requirements.

In Summary, NPCC concerns are as follows-

a) Québec Area is not synchronously interconnected with the rest of the Eastern Interconnexion thus i) coordination requirements are limited within its synchronous system, ii) ultimate source and sink are limited within its synchronous system
b) NY's, NE's, IESO 's transmission commitments are not based point to point transmission reservations in both operating and planning horizon thus posting requirement will not include ATC based on physical reservation and we believe that ATC is a market based quantity.
c) CBM is more or less a physical reservation made, at no cost, by LSEs within the boundaries of the TP's system. Therefore for some members of NPCC, because they have market based systems and are not using physical reservations, feel a standard NERC Standards for CBM is not necessary.
d) Some of NPCC's Areas have confidentiality issues especially with Generator outage schedules and we are asking the drafting team to be cognizant of these and respect this confidentiality.

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
**and**
**Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0**

This form is to be used to submit comments on Draft 1 of two individual SARs: 1) Proposed Revisions to Existing Standard Number MOD-001-0 dealing with AFC/ATC/TTC; and 2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 dealing with CBM/TRM. Comments must be submitted by **August 08, 2005**. You may submit the completed form by emailing it to: sarcomm@nerc.com with the words "ATC/TTC/CBM/TRM Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

**ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE AND IT IS THEREFORE IMPORTANT TO ADHERE TO THE FOLLOWING REQUIREMENTS:**

**DO:** **Do** enter text only, with no formatting or styles added.
**Do** use punctuation and capitalization as needed (except quotations).
**Do** use more than one form if responses do not fit in the spaces provided.
**Do** submit any formatted text or markups in a separate WORD file.

**DO NOT:** **Do not** insert tabs or paragraph returns in any data field.
**Do not** use numbering or bullets in any data field.
**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Mike Calimano | |
| Organization: | NYISO | |
| Telephone: | 518 356 6129 | |
| Email: | mcalimano@nyiso.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☒ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☐ | 4 - Transmission-dependent Utilities |
| ☐ MAIN | ☐ | 5 - Electric Generators |
| ☐ MAPP | ☐ | 6 - Electricity Brokers, Aggregators, and Marketers |
| ☒ NPCC | ☐ | 7 - Large Electricity End Users |
| ☐ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact Email:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information:

The Long-Term AFC/ATC Task Force (LTATF) was formed to develop specific recommendations for the calculation and coordination of AFC/ATC with the goal of increasing market liquidity and enhancing grid reliability. The task force's work was coordinated with NAESB to separate business practices from reliability concerns. The LTATF evaluated the results of the short-term recommendations in the Alliant West area for summer 2004, and used this evaluation when considering whether to recommend the Alliant West short-term recommendations continue.

In developing their recommendations the LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for ATC/TTC and CBM/TRM. The proposed "Modification to MOD-001-0 Documentation of ATC and TTC Calculation" SAR and "Modification to standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 SAR are the culmination[1] of the LTATF's work and is the subject matter for this Comment Form.

The SAC and the LTATF would like to receive industry comments on the scope and need for these two individual SARs. Accordingly, we request your comments included on this form, emailed to sarcomm@nerc.com with the subject "ATC/TTC/CBM/TRM Comments" by **August 7, 2005**.

## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
| | | R1.9 | Add/Delete Language |
| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
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| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
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| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
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1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

1. **Is there a reliability need for the proposed standard?**

   ☒ Yes

   ☐ No

   Comments:

2. **Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

   ☒ Yes

   ☐ No

   Comments: Coordination and documentation of the calculation method would improve transparancy. Standardization, however, must recognize the inherent differences between systems which employ physical transmission reservations and energy markets which use financial congestion management and not be prescriptive.

3. **Do you agree with the scope of the proposed standard?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

   **Note: NAESB has a proposal for companion business practice - R05004)**

   ☐ Yes

   ☒ No

   Comments:

5. **Do you agree with the list of entities to which the standard would apply?**

   ☒ Yes

☐ No

Comments:

**6. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes

☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments:

Secion R.1.7 - all data listed should be considered confidential and used for the purposes of  RC reliability studies.

Secion R.1.7.2 - please clarify what is meant by Generation Dispatch Order and why it is needed?

Section R.1.7.6 - please explain why this document specifies the use of tool, namely SDX, while other NERC standards such as coordinated operations are not requiring the use of a specific software tool.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☒ Yes
☐ No

Comments:

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes

☐ No

Comments: In the operation horizion the NYISO does not use CBM, however, we agree that areas that employ a non-zero CBM should coordinate and document the process.

**11. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments:

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**13. Do you agree with the list of entities to which the standard would apply?**

☒ Yes
☐ No

Comments:

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes

☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments:

## SAR Comment Form
## Proposed Revisions to Existing Standard Number MOD-001-0
## and
## Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

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**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

| Individual Commenter Information (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| Email: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☐ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☐ | 4 - Transmission-dependent Utilities |
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| ☐ MAPP | ☒ | 6 - Electricity Brokers, Aggregators, and Marketers |
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| ☒ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
**and**
**Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0**

Group Comments (Complete this page if comments are from a group.)

**Group Name:** Southern Company Generation

**Lead Contact:** **Roman Carter**

**Contact Organization:** **Southern Company Generation**

**Contact Segment:** **6**

**Contact Telephone:** **205.257.6027**

**Contact Email:** **jrcarter@southernco.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Matt Ansley | Southern Generation | SERC | 6 |
| Roger Green | Southern Generation | SERC | 5 |
| Terry Crawley | Southern Generation | SERC | 5 |
| Tom Higgins | Southern Generation | SERC | 5 |
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## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
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| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
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| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

**1. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments:

**2. Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

☐ Yes

☒ No

Comments: The standard should focus on increasing the transparency of study assumptions and methods utilized by each Transmission Service Provider (TSP), rather than attempt to prescribe or mandate the exact procedures and assumptions used in the calculation of TTC/ATC/AFC by all TSPs. Additionally, this standard should increase communication around and the coordination of transfer capability calculations. Determination of ATC is already defined within each FERC-jurisdictional TSP's Open Access Transmission Tariff (Attachment C of the pro-forma OATT). There is no reliability need to mandate a prescribed detailed procedure and assumptions for calculating TTC/ATC/AFC.

**3. Do you agree with the scope of the proposed standard?**

☐ Yes

☒ No

Comments: See comments in response to Question 2 above. In addition, clarification should be provided with respect to the applicability of any portions of a standard to either short-term and long-term service (as defined in FERC Order 888, 889, 638, etc.) TTC/ATC study methods. The scope is too broad in terms of requiring data that is commercially sensitive (e.g., generation dispatch order); any data to be shared should be adequately protected; and data only needs to be made available if it is truly relevant to the study process.

**4. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments: We would like to emphasize that CBM should remain in this standard due to it being a critical component of Grid reliability and should not become a business practice in a NAESB standard.

5. **Do you agree with the list of entities to which the standard would apply?**

☐ Yes

☒ No

Comments: RTO/ISOs should be required to provide the same documentation for their assumptions and methods.

6. **Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments: It should be pointed out that this standard should contain consistent definitions, including but not limited to, ATC, AFC, TTC, CBM, and TRM. The definitions should be developed as part of the industry effort of this standard.

7. **Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes

☒ No

Comments:

8. **Do you have any other comments on these proposed standards?**

Comments: While this SAR suggests that individual transmission owners and operators within an RTO or ISO may be exempt from developing and documenting a regional methodology for TTC/ATC/AFC determination, we expect that the RTO/ISO would not be exempt from clearly documenting their assumptions and methods. Maintaining this requirement will help to ensure the same transparency exists for the RTO/ISO footprint as in other regions.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☐ Yes

☒ No

Comments: There is a reliability need for communication and coordination of TTC, CBM, and TRM determination, but no reliability need exists for every Transmission Service Provider to utilize the exact same methods to determine these values.

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes

☐ No

Comments: Availibility of CBM is an integral part of overall system reliability for each entity that relies on it as part of its generation adequacy calculations.

**11. Do you agree with the scope of the proposed standard?**

☐ Yes

☒ No

Comments: As with the SAR for MOD-001-0, the scope of this SAR goes beyond what is required for system relaibility. There is no reliability need to prescribe in detail how each entity should calculate either TRM or CBM. There is a need to ensure transparancy in the methodology used by each entity but not in the specific components of the calculation.

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes
☒ No

Comments: RTO/ISOs should be required to provide the same documentation for their assumptions and methods.

**14. Do you have any other terms that should be included in the definitions?**

☒ Yes
☐ No

Comments: Please define "Calculation Model" as described in requirement R1.7.9.

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes
☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments: If this standard is developed  beyond the transparancy issue, the methodology should only mandate that certain guiding priciples be considered in the determination of TRM and CBM and not that a industry-wide prescriptive set of calculations be made.  Also it should be up to each entity with responsibility for their own system reliability and generation adequacy on how internal generation should be considered in the determination of CBM and thus generation adequacy within their system.

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
**and**
**Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0**

This form is to be used to submit comments on Draft 1 of two individual SARs: 1) Proposed Revisions to Existing Standard Number MOD-001-0 dealing with AFC/ATC/TTC; and 2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 dealing with CBM/TRM. Comments must be submitted by **August 08, 2005**. You may submit the completed form by emailing it to: sarcomm@nerc.com with the words "ATC/TTC/CBM/TRM Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

**ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE AND IT IS THEREFORE IMPORTANT TO ADHERE TO THE FOLLOWING REQUIREMENTS:**

**DO:** **Do** enter text only, with no formatting or styles added.
**Do** use punctuation and capitalization as needed (except quotations).
**Do** use more than one form if responses do not fit in the spaces provided.
**Do** submit any formatted text or markups in a separate WORD file.

**DO NOT:** **Do not** insert tabs or paragraph returns in any data field.
**Do not** use numbering or bullets in any data field.
**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| Email: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☐ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☐ | 4 - Transmission-dependent Utilities |
| ☐ MAIN | ☐ | 5 - Electric Generators |
| ☐ MAPP | ☐ | 6 - Electricity Brokers, Aggregators, and Marketers |
| ☐ NPCC | ☐ | 7 - Large Electricity End Users |
| ☐ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

## SAR Comment Form
## Proposed Revisions to Existing Standard Number MOD-001-0
## and
## Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

Group Comments (Complete this page if comments are from a group.)

**Group Name:** Southern Company - Transmission

**Lead Contact:** **Marc M. Butts**

**Contact Organization:** **Southern Company Services**

**Contact Segment:** **1**

**Contact Telephone:** **205-257-4839**

**Contact Email:** **mmbutts@southernco.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Raymond Vice | Southern Company Services | SERC | 1 |
| Keith Calhoun | Southern Company Services | SERC | 1 |
| Jim Busbin | Southern Company Services | SERC | 1 |
| Jim Viikinsalo | Southern Company Services | SERC | 1 |
| Doug McLaughlin | Southern Company Services | SERC | 1 |
| Jim Griffith | Southern Company Services | SERC | 1 |
| Steve Corbin | Southern Company Services | SERC | 1 |
| Dean Ulch | Southern Company Services | SERC | 1 |
| Mike Robinson | Southern Company Services | SERC | 1 |
| Matt Guillebaud | Southern Company Services | SERC | 1 |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information:

The Long-Term AFC/ATC Task Force (LTATF) was formed to develop specific recommendations for the calculation and coordination of AFC/ATC with the goal of increasing market liquidity and enhancing grid reliability. The task force's work was coordinated with NAESB to separate business practices from reliability concerns. The LTATF evaluated the results of the short-term recommendations in the Alliant West area for summer 2004, and used this evaluation when considering whether to recommend the Alliant West short-term recommendations continue.

In developing their recommendations the LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for ATC/TTC and CBM/TRM. The proposed "Modification to MOD-001-0 Documentation of ATC and TTC Calculation" SAR and "Modification to standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 SAR are the culmination[1] of the LTATF's work and is the subject matter for this Comment Form.

The SAC and the LTATF would like to receive industry comments on the scope and need for these two individual SARs. Accordingly, we request your comments included on this form, emailed to sarcomm@nerc.com with the subject "ATC/TTC/CBM/TRM Comments" by **August 7, 2005**.

## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.6 | Add/Delete Language |
| | | R1.7 | Add/Delete Language |
| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
| | | R1.9 | Add/Delete Language |
| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

**1. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments:

**2. Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

☐ Yes

☒ No

Comments: The standard should focus on increasing the transparency of study assumptions and methods utilized by each Transmission Service Provider (TSP), rather than attempt to prescribe or mandate the exact procedures and assumptions used in the calculation of TTC/ATC/AFC by all TSPs. Determination of ATC is already defined within each FERC-jurisdictional TSP's Open Access Transmission Tariff (Attachment C of the pro-forma OATT). There is no reliability need to mandate a prescribed, detailed procedure and assumptions for calculating TTC/ATC/AFC.

**3. Do you agree with the scope of the proposed standard?**

☐ Yes

☒ No

Comments: See comments in response to Question 2 above. Additionally, clarification should be provided with respect to the applicability of any portions of a standard to either short-term and long-term (service as defined in FERC Order 888, 889, 638, etc.) TTC/ATC study methods. The scope is too broad in terms of requiring data that is commercially sensitive (e.g., generation dispatch order); any data to be shared should be adequately protected; and data only needs to be made available if it is truly relevant to the study process.

**4. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments: We believe CBM should remain in this standard due to it being a critical component of Grid reliability and should not become a business practice in a NAESB standard.

**5. Do you agree with the list of entities to which the standard would apply?**

☐ Yes
☒ No

Comments: No. See comment in Question #8.

**6. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes
☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments: While this SAR suggests that individual transmission owners and operators within an RTO or ISO may be exempt from developing and documenting a regional methodology for TTC/ATC/AFC determination, we expect that the RTO/ISO would not be exempt from clearly documenting their assumptions and methods.  Maintaining this requirement will help to ensure the same transparency exists for the RTO/ISO footprint as in other regions.

# CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☐ Yes

☒ No

Comments: There is a reliability need for communication and coordination of TTC, CBM, and TRM determination, but no reliability need exists for every Transmission Service Provider to utilize the exact same methods to determine these values.

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes

☐ No

Comments: Availability of CBM is an integral part of overall system reliability for each entity that relies on it as part of its generation adequacy calculations.

**11. Do you agree with the scope of the proposed standard?**

☐ Yes

☒ No

Comments: As with the SAR for MOD-001-0, the scope of this SAR goes beyond what is required for system reliability. There is no reliability need to prescribe in detail how each entity should calculate either TRM or CBM. There is a need to ensure transparency in the methodology used by each entity, but not in the specific components of the calculation.

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☐ Yes

☒ No

Comments:

**13. Do you agree with the list of entities to which the standard would apply?**

☐ Yes
☒ No

Comments: Similar to the comments supplied in response to Question 8, we expect that all regions will be expected to clearly document their assumptions and methods, regardless of operational or organizational structure, in order to ensure transparency.

**14. Do you have any other terms that should be included in the definitions?**

☒ Yes

☐ No

Comments: Please define "Calculation Model" as described in requirement R1.7.9.

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes
☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments: If a standard is developed that extends beyond the basic assurance of transparency, any resulting method should only mandate that certain guiding principles be considered in the determination of TRM and CBM - rather than mandate that a prescriptive set of calculations be made. Furthermore, each entity responsible for the generation adequacy of their system should be the one to determine how best to consider their own internal generation for use in the determination of an appropriate CBM value for that specific system.

**SAR Comment Form**
**Proposed Revisions to Existing Standard Number MOD-001-0**
**and**
**Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0**

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**Do not** use numbering or bullets in any data field.
**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Christopher Plante |
| Organization: | WPS Resources |
| Telephone: | 920-433-1290 |
| Email: | cplante@wpsr.com |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☐ | 1 - Transmission Owners |
| ☐ ECAR | ☐ | 2 - RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 - Load-serving Entities |
| ☐ MAAC | ☒ | 4 - Transmission-dependent Utilities |
| ☒ MAIN | ☐ | 5 - Electric Generators |
| ☐ MAPP | ☐ | 6 - Electricity Brokers, Aggregators, and Marketers |
| ☐ NPCC | ☐ | 7 - Large Electricity End Users |
| ☐ SERC | ☐ | 8 - Small Electricity End Users |
| ☐ SPP | ☐ | 9 - Federal, State, Provincial Regulatory or other Government Entities |
| ☐ WECC | | |
| ☐ NA - Not Applicable | | |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact Email:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information:

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## Tabular Summary of Requirement Changes

| SAR | Existing Standard | Requirement | Change |
|---|---|---|---|
| 1) | MOD-001-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
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| | | R1.7.1 | Add Requirement |
| | | R.1.7.2 | Add Requirement |
| | | R1.7.3 | Add Requirement |
| | | R1.7.4 | Add Requirement |
| | | R1.7.5 | Add Requirement |
| | | R1.7.6 | Add Requirement |

[1] The LTATF also developed a proposed business practice that was submitted to NAESB.

| | | | |
|---|---|---|---|
| | | R1.7.7 | Add Requirement |
| | | R1.7.8 | Add Requirement |
| | | R1.7.9 | Add Requirement |
| | | R1.7.10 | Add Requirement |
| | | R1.8 | Add/Delete Language |
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| | | R1.10 | Add Requirement |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | | R3 | Add Requirement |
| 2) | MOD-004-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.4 | Add/Delete Language |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.5.2 | Add Requirement |
| | | R1.6 | Add/Delete Language |
| | | R1.6.1 | Add Requirement |
| | | R1.7.1 | Add Requirement |
| | | R1.10 | Add/Delete Language |
| | | R1.11 | Add Requirement |
| | | R1.12 | Add Requirement |
| | | R2 | Add/Delete Language |
| | MOD-005-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |

| | | | |
|---|---|---|---|
| | | R3 | Add/Delete Language |
| | MOD-006-0 | Entire | Withdraw |
| | MOD-008-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.9 | Add Requirement |
| | | R1.3.10 | Add Requirement |
| | | R1.5 | Add/Delete Language |
| | | R1.5.1 | Add Requirement |
| | | R1.6 | Add Requirement |
| | | R1.7 | Add Requirement |
| | | R1.8 | Add Requirement |
| | | R1.8.1 | Add Requirement |
| | | R1.8.2 | Add Requirement |
| | MOD-009-0 | R1 | Add/Delete Language |
| | | R1.1 | Add/Delete Language |
| | | R1.2 | Add/Delete Language |
| | | R1.3 | Add/Delete Language |
| | | R1.3.1 | Add Requirement |
| | | R1.4 | Add/Delete Language |
| | | R2 | Add/Delete Language |
| | | R3 | Add/Delete Language |
| | | R4 | Add Requirement |

1) Proposed Revisions to Existing Standard Number MOD-001-0 (AFC/ATC/TTC)

2) Proposed Revisions to Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0 (CBM/TRM)

# AFC/ATC/TTC SAR Regarding Existing Standard MOD-001-0

1. **Is there a reliability need for the proposed standard?**

   ☒ Yes

   ☐ No

   Comments:

2. **Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?**

   ☒ Yes

   ☐ No

   Comments:

3. **Do you agree with the scope of the proposed standard?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

   **Note: NAESB has a proposal for companion business practice - R05004)**

   ☒ Yes

   ☐ No

   Comments: NAESB business practice R05004.

5. **Do you agree with the list of entities to which the standard would apply?**

   ☒ Yes

   ☐ No

   Comments:

**6. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?**

☐ Yes

☒ No

Comments:

**8. Do you have any other comments on these proposed standards?**

Comments: As written, the proposed standards do not require an RTO/ISO to develop and document an AFC/TTC/ATC methodology consistent with the standards. Section B (R1) must inlcude language to ensure that the standard also applies to an RTO/ISO performing AFC/TTC/ATC calculations.

Throughout the proposed standard, there is not a consistent reference to AFC and TTC/ATC. For example, some areas of the SAR refer only to AFC and other areas refer to TTC/ATC. All requirements of the proposed standard should apply to all three quantities, AFC/TTC/ATC.

## CBM/TRM SAR Regarding Existing Standards MOD-004-0, MOD-005-0, MOD-006-0, MOD-008-0, and MOD-009-0

**9. Is there a reliability need for the proposed standard?**

☒ Yes

☐ No

Comments:

**10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard? Y/N Comment?**

☒ Yes

☐ No

Comments: But, only to the extent that the resource adequacy requirement of the CBM region assumes support from external resources AND the transmission system of the CBM region is planned and built to accommodate the CBM amount.

**11. Do you agree with the scope of the proposed standard?**

☒ Yes

☐ No

Comments:

**12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?**

**Note: NAESB has a proposal for companion business practice - R05004)**

☒ Yes

☐ No

Comments: NAESB business practice R05004.

**13. Do you agree with the list of entities to which the standard would apply?**

☒ Yes

☐ No

Comments:

**14. Do you have any other terms that should be included in the definitions?**

☐ Yes

☒ No

Comments:

**15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?**

☐ Yes

☒ No

Comments:

**16. Do you have any other comments on these proposed standards?**

Comments: As written, the proposed standards do not require an RTO/ISO to develop and document a CBM/TRM methodology consistent with the standards. Section R1 of MOD-004-00 must inlcude language to ensure that the standard also applies to an RTO/ISO performing CBM/TRM calculations.

Within section R1.5 (note numbering error in this section of the SAR) of the CBM methodology (allocation of CBM to interfaces), the methodology should require the specification and rational for the selection of source and sink points to simulate the import of the CBM amount, if a simulation is performed. The source and sink points must be consistent with those used by the transmission owner/service provider in their CBM planning studies.

The CBM/TRM SAR should include a requirement that the methodology specify how CBM/TRM is incoporated in the AFC/ATC/TTC calculations (firm, nonfirm, or both). If CBM/TRM is applied within a market structure that utilizes a security constrained centrally dispatch system (locational marginal pricing), the SAR should require the that CBM/TRM methodology specify how it is applied in financial transmission rights models, day-ahead models, and real-time models.

# Questions 1 – 8 apply to ATC/TTC/AFC SAR
# Questions 9 – 16 apply to CBM/TRM SAR

1. Is there a reliability need for the proposed standard?

| Commenter | Yes | No | Comment | Response |
|---|---|---|---|---|
| Summary | | | In general, most people felt that there is a reliability need for the proposed standard.<br><br>Most of the parties that responded had no comments, however two that did comment felt that TTC and TRM were reliability quantities and that ATC and AFC were market quantities.<br><br>Nearly all commented that yes there is a reliability need – Of the 14 that responded only four commented with any level of negative response, but just for ATC. These four stressed TTC is a reliability quantity and should be addressed. | The ATCT SAR drafting team agrees that there is a reliability need for the proposed standard, and believes that TTC/ATC are not reliability indicators, but are derived from reliability-based values, assumptions and criteria. However, there is a need to acknowledge the relationship between TTC and ATC values. The drafting team believes that both these quantities should be addressed by this reliability standard. |
| WPS Resources<br>Christopher Plante | X | | | |
| Southern company – Transmission<br>Marc M. Butts<br>Raymond Vice<br>Keith Calhoun<br>Jim Viikinsalo<br>Doug McLaughlin<br>Jim Griffith<br>Steve Corbin<br>Dean Ulch<br>Mike Robinson<br>Matt Guillebaud | X | | | |
| Southern Company Generation<br>Roman Carter<br>Matt Ansley<br>Roger Green<br>Terry Crawley<br>Tom Higgins | X | | | |
| NYISO<br>Mike Calimano | X | | | |
| ATC Task Force of NERC | X | | Yes – It is important to recognize that while | The drafting team agrees with the comment. |

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| Planning Committee<br>Paul B. Johnson – American Electric Power<br>Tomas C. Mielnik – Mid American Energy Co.<br>William Harm – PJM International<br>Ronald F. Szymaczak – Exelon<br>Thomas E. Washburn – Orlando Utilities<br>Lee Westbrook – TXU Electric Del.<br>Virginia C. Sulzberger - NERC | | | AFC/ATC/TTC are not indicators of reliability, AFC/ATC/TTC values are limited by NERC standards and definitions, Regional criteria, and the physical characteristics of the interconnected electric systems. The proper calculation and use of AFC/ATC/TTC are critical to maintaining system reliability. | |
| North Carolina Municipal Power Agency Number 1.<br>Matt Schull | X | | | |
| RTO/ISO Standards Review Committee<br>Anita Lee – AESO<br>William Phillips – MISO<br>Sam Jones – ERCOT<br>Ron Falsetti - IESO<br>Peter Brandien – ISO – NE<br>Karl Tammar – NYISO<br>Bruce Balmat – PJM<br>Charles Yeung – SPP<br>Lisa Szot - CAISO | X | | | |
| ISO-NE<br>Kathleen M. Goodman | X | | | |
| Ontario – Independent Electricity System Operator<br>Ron Falsetti | X | | | |
| Hydro-Quebec Trans Energie<br>Soulier Daniel<br>Victor Bissonnette | X | X | Yes for TTC: TTCs reflect the operating/planning system conditions thus have to be accurate to achieve system reliability<br>No for ATC/AFC : ATCs/AFCs are quantities that are based on different market rules to access the transmission systems and to manage system congestion. Thus ATC and AFC should be market driven | The ATCT SAR drafting team agrees that there is a reliability need for the proposed standard, and believes that TTC/ATC are not reliability indicators, but are derived from reliability-based values, assumptions and criteria. However, there is a need to acknowledge the relationship between TTC and ATC values. The drafting team believes that both these quantities should be addressed by this reliability standard. |
| FRCC<br>John Odom – FRCC<br>Tom Washburn – OUC | X | | Reliability must be maintained at all times including accounting for planned outages and unexpected dynamic system conditions, while at the same time providing for | The drafting team agrees |

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| Gary Brinkworth – City of Tallahassee<br>Paul Elwing – Lakeland Electric<br>Carter Edge – Southeastern Power Admin.<br>Roger Westphal – Gainesville Regional Utilities<br>Bob Schoneck – Fl. Power & Light<br>Don McInnis – Fl. Power & Light<br>Kiko Barredo – Fl. Power & Light<br>Paul Graves – Progress Energy FLA<br>Ron Donahey – Tampa Electric Co. | | | ATC/AFC to users of the the system. Therefore there is a reliability need for this standard. A transmission system has finite capability and the provision for a transmission reliability margin (TRM) is an important component in determining ATC/AFC and is necessary to take into account such varied system conditions in order to maintain reliability while not overstating the ATC/AFC. However, the ATC values are not reliability indicators, but rather the ATC values are derived from reliability based values, assumptions and criteria. | |
| Northeast Power Coordinating Council<br>Guy V. Zito | X | X | TTC and TRM are reliability driven quantities however ATC/AFCs are quantities that are based on market rules and used in the managing of system congestion. ATC/AFC calculations are not required to achieve Reliability | The drafting team believes that TTC/ATC are not reliability indicators, but are derived from reliability-based values, assumptions and criteria. However, there is a need to acknowledge the relationship between TTC and ATC values. The drafting team believes that both these quantities should be addressed by this reliability standard. |
| Exelon<br>Ronald Szymaczak | | | | |
| MRO<br>Ken Goldsmith – MRO<br>Al Boesch – NPPD<br>Terry Bilke – MISO<br>Robert Coish – MHEB<br>Dennis Florom – LES<br>Todd Gosnell – OPPD<br>Wayne Guttormson – SPC<br>Jim Maenner - WPS<br>Tom Mielnik – MEC<br>Darrick Moe – WAPA<br>Joe Knight – MRO<br>30 Additional MRO Memebers<br>*Alliant Energy does not agree with these comments | X | | | |

2. Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC and TTC?

| Commenter | Yes | No | Comment | Response |
|---|---|---|---|---|
| Total: | | | | |
| | | | Of 14 responses, 6 were “yes”, 6 were “no”, and 2 were “yes and no”. The majority of comments are in agreement, however.<br><br>In general, most people disagree with the idea of a standard methodology for ATC/TTC/AFC calculation. NCMPA1 is the only exception.<br><br>Nearly all commented about the need for increased data exchange, coordination, and documentation to promote transparency. | The DT believes that each entity, in complying with the standard, should clearly document the fundamental components of its transfer capability calculations and make such documentation transparent to the marketplace.<br><br>While the specifics of each calculation may differ to accommodate regional variances, the goal of the standard is to ensure that entities are generating results that are in agreement and foster better coordination and communications between themselves.<br><br>When a commenter refers to “standard methodology”, it is unclear if they are referring to a standard method for only Total Transfer Capability (TTC), Available Transfer Capability (ATC), or Available Flowgate Capability (AFC) or for all three.<br><br>The SAR drafting recognizes the need for clarification and regional standardization of these issues, and will refer them to the Standard Drafting Team. |
| WPS Resources<br>Christopher Plante | X | | | |
| Southern company – Transmission | | X | The standard should focus on increasing the transparency of study assumptions and methods utilized by each Transmission Service Provider (TSP), rather than attempt to prescribe or mandate the exact procedures and assumptions used in the calculation of TTC/ATC/AFC by all TSPs. Determination of ATC is already defined within each FERC-jurisdictional TSP's Open Access Transmission Tariff (Attachment C of the pro-forma OATT). There is no reliability need to mandate a prescribed, detailed procedure and assumptions for calculating TTC/ATC/AFC. | While the specifics of each calculation may differ to accommodate regional variances, the goal of the standard is to ensure that entities are generating results that are in agreement and foster better coordination and communications between themselves. |
| Southern Company Generation | | X | The standard should focus on increasing the transparency of study assumptions and methods utilized by each Transmission Service Provider (TSP), rather than attempt to prescribe or mandate the exact procedures and assumptions used in the calculation of TTC/ATC/AFC by all TSPs. Additionally, this standard should increase | While the specifics of each calculation may differ to accommodate regional variances, the goal of the standard is to ensure that entities are generating results that are in agreement and foster better coordination and communications between themselves. |

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| | | | communication around and the coordination of transfer capability calculations. Determination of ATC is already defined within each FERC-jurisdictional TSP's Open Access Transmission Tariff (Attachment C of the pro-forma OATT). There is no reliability need to mandate a prescribed detailed procedure and assumptions for calculating TTC/ATC/AFC. | |
| NYISO | X | | Coordination and documentation of the calculation method would improve transparency. Standardization, however, must recognize the inherent differences between systems which employ physical transmission reservations and energy markets which use financial congestion management and not be prescriptive | Standardization must recognize inherent differences between markets. ATCT DT will work with this concern as regional difference.<br>Coordination and documentation of calculation method would improve transparency. |
| ATC Task Force of NERC Planning Committee | | X | No – The NERC Planning Committee encourages further standardization of certain key elements and parameters in the calculation of ATC, AFC, and TTC. The proposed standards on ATC, AFC, and TTC calculations must require that key elements of the calculation critical to reliability be incorporated into any proposed NERC ATC and TTC standard methodology and strengthened for increased consistency.<br><br>The existing NERC ATC and TTC methodology prescribes a set of requirements that must be addressed in calculating ATC and TTC values. While the current methodology provides a degree of commonality in the calculations, that commonality needs to be strengthened. This strengthening of the calculation requirements refers to additions and refinements to the elements or parameters to be addressed in the calculation methodology and not to the tools or equipment used for the calculations.<br><br>Some examples of the elements critical to reliability and for which further standardization in the ATC and TTC calculations should be required include: 1) coordination in the exchange and use of system data within the Regions and among adjacent Regions, 2) the monitoring of critical limiting transmission facilities under appropriate contingencies consistent with planning and operating criteria, 3) consistency in the manner in which transmission services are reserved, scheduled, and accounted in the calculations, 4) using appropriate | The DT believes that each entity, in complying with the standard, should clearly document the fundamental components of its transfer capability calculations and make such documentation transparent to the marketplace.<br><br>While the specifics of each calculation may differ to accommodate regional variances, the goal of the standard is to ensure that entities are generating results that are in agreement and foster better coordination and communications between themselves.<br><br>When a commenter refers to "standard methodology", it is unclear if they are referring to a standard method for only Total Transfer Capability (TTC), Available Transfer Capability (ATC), or Available Flowgate Capability (AFC) or for all three.<br><br>The SAR drafting recognizes the need for clarification and regional standardization of these issues, and will refer them to the Standard Drafting Team. |

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| | | | generation dispatches, 5) meeting a minimum frequency of ATC and TTC calculations, 6) base case model building (i.e., what data needs to be incorporated and updated), 7) ATC and TTC calculators (those who are responsible for calculating ATC and TTC values) who impact each other's transmission system must have appropriate and adequate model representation (load level, generation dispatch, transmission and generation outages) of each other's system, and 8) monitoring of transmission facilities based on the use of an appropriate distribution cutoff factor.<br><br>Further, AFC (available flowgate capability) must be clearly defined. The NERC ATC and TTC methodology must be expanded to include and describe the key elements that must be addressed in the calculation of AFC values. In addition, the relationship of AFC to ATC and TTC must be clearly defined along with the manner in which they will be used and coordinated in accounting for transmission reservations and schedules. | |
| North Carolina Municipal Power Agency Number 1. | | X | ATC/TTC/AFC calculations should be standardized across all regions. The way the SAR is written now, TSPs within a region will be required to coordinate methodology and calculations, but the regions will not be required to coordinate with each other. Without standardized calculations and coordination between regions, we will continue to have differences in regional ATC/TTC/AFC values and limit commercial activity. Rather than having calculation differences between neighboring TSPs as it is today, it will just be pushed up to the regional level and the problem of uncoordinated ATC/TTC/AFC values will remain. | While the specifics of each calculation may differ to accommodate regional variances, the goal of the standard is to ensure that entities are generating results that are in agreement and foster better coordination and communications between themselves. |
| RTO/ISO Standards Review Committee | X | X | We agree that the proposed scope of the standard is sufficient to address reliability concerns. We disagree that there needs to be a standard method for calculation of ATC, AFC and TTC for all ISOs/RTOs. Some differences in methodologies (market, non-market, etc.) may exist, but the processes must be coordinated and work together. | The drafting team realizes that differences in implementing methodologies may exist, but the processes must be coordinated and work together. |
| ISO-NE | X | | | |
| Ontario – Independent Electricity System Operator | X | X | IESO agrees that the proposed scope of the standard is sufficient to address reliability concerns. IESO disagrees | The DT believes that each entity, in complying with the standard, should clearly document the fundamental components of its transfer |

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| | | | that there needs to be a standard method for calculation of ATC, AFC and TTC for all ISOs/RTOs. Some differences in methodologies (market, non-market, etc.) may exist, but the processes must be coordinated and work together. | capability calculations and make such documentation transparent to the marketplace.<br><br>While the specifics of each calculation may differ to accommodate regional variances, the goal of the standard is to ensure that entities are generating results that are in agreement and foster better coordination and communications between themselves.<br><br>When a commenter refers to “standard methodology”, it is unclear if they are referring to a standard method for only Total Transfer Capability (TTC), Available Transfer Capability (ATC), or Available Flowgate Capability (AFC) or for all three.<br><br>The SAR drafting recognizes the need for clarification and regional standardization of these issues, and will refer them to the Standard Drafting Team. |
| Hydro-Quebec Trans Energie | X | | The proposed standard is already going too much into methodology details | The drafting team disagrees, we believe it has an appropriate amount of detail. |
| FRCC | | X | The proposed standard should require that ATC/AFC values be coordinated across interfaces. The standard should not require one specific uniform methodology for each ATC/AFC calculator for calculating ATC, AFC and TTC, but should require that the Regional Reliability Organizations (including RTO/ISOs) develop a region wide methodology that meets the needs of each respective Planning Authority within the region, such that when applied by individual ATC/AFC calculators would produce consistent results at all interfaces. | The DT believes that each entity, in complying with the standard, should clearly document the fundamental components of its transfer capability calculations and make such documentation transparent to the marketplace.<br><br>While the specifics of each calculation may differ to accommodate regional variances, the goal of the standard is to ensure that entities are generating results that are in agreement and foster better coordination and communications between themselves.<br><br>When a commenter refers to “standard methodology”, it is unclear if they are referring to a standard method for only Total Transfer Capability (TTC), Available Transfer Capability (ATC), or Available Flowgate Capability (AFC) or for all three.<br><br>The SAR drafting recognizes the need for clarification and regional standardization of these issues, and will refer them to the Standard Drafting Team. |
| Northeast Power Coordinating Council<br>Guy V. Zito | X | | Although it is agreed that the proposed scope is sufficient to address reliability objectives, we disagree that there needs to be a standard outlining the method for calculation of ATC/AFC. There are different market structures in the Northeast and the processes need to be | The DT believes that each entity, in complying with the standard, should clearly document the fundamental components of its transfer capability calculations and make such documentation transparent to the marketplace. |

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| | | | coordinated to ensure they work together to achieve a transparent, documented methodology to calculate those quantities that are critical to maintaining reliability objectives. | While the specifics of each calculation may differ to accommodate regional variances, the goal of the standard is to ensure that entities are generating results that are in agreement and foster better coordination and communications between themselves.<br><br>When a commenter refers to “standard methodology”, it is unclear if they are referring to a standard method for only Total Transfer Capability (TTC), Available Transfer Capability (ATC), or Available Flowgate Capability (AFC) or for all three.<br><br>The SAR drafting recognizes the need for clarification and regional standardization of these issues, and will refer them to the Standard Drafting Team. |
| Exelon | | X | The standard must state that aspects of the calculation critical to the reliability be required in the methodologies. Some examples of the aspects critical to reliability are exchange and use of data, monitoring all critical flow gates and meeting a minimum frequency of calculation. These items and any others must be required in the methodologies. What method the ATC calculator uses to accomplish these critical aspects is up to them and therefore a standard method should not be required. | The DT believes that each entity, in complying with the standard, should clearly document the fundamental components of its transfer capability calculations and make such documentation transparent to the marketplace.<br><br>While the specifics of each calculation may differ to accommodate regional variances, the goal of the standard is to ensure that entities are generating results that are in agreement and foster better coordination and communications between themselves.<br><br>The SAR drafting recognizes the need for clarification and regional standardization of these issues, and will refer them to the Standard Drafting Team. |
| MRO<br><br>*Alliant Energy does not agree with these comments | X | | | The DT believes that each entity, in complying with the standard, should clearly document the fundamental components of its transfer capability calculations and make such documentation transparent to the marketplace.<br><br>While the specifics of each calculation may differ to accommodate regional variances, the goal of the standard is to ensure that entities are generating results that are in agreement and foster better coordination and communications between themselves.<br><br>When a commenter refers to “standard methodology”, it is unclear if they are referring to a standard method for only Total Transfer Capability (TTC), Available Transfer Capability (ATC), or Available Flowgate Capability (AFC) or for all three. |

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| | | | | The SAR drafting recognizes the need for clarification and regional standardization of these issues, and will refer them to the Standard Drafting Team. |

3. Do you agree with the scope of the proposed standard?

| Commenter | Yes | No | Comment | Response |
|---|---|---|---|---|
| Total: | | | | |
| | | | In general, most people felt that the scope of the proposed standard was appropriate. A simple tally of the 14 Yes or No responses comes to 9 Yes, 4 No with one Yes and No. This question (#3) is related to the responses to question #2, and several responders to question #3 simply referred to comments in their response to #2.<br><br>Most felt that standardization *of the particular method of ATC/TTC calculation (i.e. a prescriptive requirement)* was not necessary, although several felt that further standardization of certain coordination elements would improve and strengthen the ATC/TTC calculation process (from responses to question #2).<br><br>some asked for clarification on the applicability of any portion of a standard to either short-term or long-term (service as defined in FERC Order 888,889,638, etc.) TTC/ATC study methods. | The drafting team agrees with the scope of the standard. |
| WPS Resources | X | | | |
| Southern Company Transmission | | X | See comments in response to Question 2 above. Additionally, clarification should be provided with respect to the applicability of any portions of a standard to either short-term and long-term (service as defined in FERC Order 888, 889, 638, etc.) TTC/ATC study methods. The scope is too broad in terms of requiring data that is commercially sensitive (e.g., generation dispatch order); any data to be shared should be adequately protected; and data only needs to be made available if it is truly relevant to the study process. | The drafting team agrees with the scope of the standard.<br><br>The SAR drafting team acknowledges the importance of protecting commercially sensitive information. |
| Southern Company Generation | | X | See comments in response to Question 2 above. In addition, clarification should be provided with respect to the applicability of any portions of a standard to either short-term and long-term service (as defined in FERC Order 888, 889, 638, etc.) TTC/ATC study methods. The scope is too broad in terms of requiring data that is commercially sensitive (e.g., generation dispatch order); any data to be shared should be adequately protected; and data only needs to be made available if it is truly relevant to the study process. | The drafting team agrees with the scope of the standard.<br><br>The SAR drafting team acknowledges the importance of protecting commercially sensitive information. |

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| NYISO | X | | | |
| ATC Task Force of NERC Planning Committee | | X | No – Please see comments provided in response to Question 2. | See response to question 2 |
| North Carolina Municipal Power Agency Number 1. | | X | The scope should include standardized ATC/TTC/AFC calculations and required coordination between regions. | More standardization and greater coordination between regions is a global theme of the LTATF report and their recommendations and the primary goal of the drafting team. The LTATF also recognized, however that a single prescriptive methodology would not be appropriate because regional and market model differences must be accommodated for a standard that will apply to all calculators. |
| RTO/ISO Standards Review Committee | X | | | |
| ISO-NE | X | | | |
| Ontario – Independent Electricity System Operator | X | | | |
| Hydro-Quebec Trans Energie | X | | The standard should be limited to TTC/TFC for reliability purposes and ATC/AFC should addressed by NAESB. | The responder apparently feels that only TTC and TFC are quantities that have reliability significance, while ATCs and AFCs are manipulated by differing market rules (from response to #1).<br><br>The drafting team disagrees; the calculation of TTC/TFC and ATC/AFC (because ATC/AFC are not independent of TTC/TFC, rather they are a subset of TTC/TFC) requires adherence to reliability standards (the purpose of this team), sound engineering principles and good utility practices which are not market rules that could be delegated to NAESB. (See proposed NAESB business practice R05004) |
| FRCC | X | | | |
| Northeast Power Coordinating Council | X | | | |
| Exelon | X | | | |
| MRO<br>*Alliant Energy does not agree with these comments | X | | | |

4. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?
Note: NAESB has a proposal for companion business practice - R05004)

| Commenter | Yes | No | Comment | Response |
|---|---|---|---|---|
| Total: | | | | |
| Total | | | Of 14 responses, 4 were “yes”, 10 were “no”.<br><br>Some commenters indicated that some aspects of the calculation should be developed as business practices by NAESB. There was one comment focused on the separation between business practices and reliability issues. A couple of entities indicated the need for CBM to be included in this standard and not in a business practice standard | NAESB has a proposal for companion business practice - R05004<br><br>R05004 has been revised to deal more specifically with related business practice issues. |
| WPS Resources | X | | | |
| Southern company – Transmission | | X | We believe CBM should remain in this standard due to it being a critical component of Grid reliability and should not become a business practice in a NAESB standard. | CBM is addressed in a companion SAR on CBM/TRM. |
| Southern Company Generation | | X | We would like to emphasize that CBM should remain in this standard due to it being a critical component of Grid reliability and should not become a business practice in a NAESB standard. | CBM is addressed in a companion SAR on CBM/TRM. |
| NYISO | | X | | |
| ATC Task Force of NERC Planning Committee | X | | Yes – The business process flow of requesting transmission service, the evaluation of a transmission service request against the calculated ATC, TTC, or AFC values, and the communication of the resulting service to the transmission user are possible elements to be considered in business practice standards. In developing the business practices, care must be taken to ensure that the tools or equipment to implement this process flow not be specified, only the process flow. All aspects dealing with reliability must be handled by NERC | To the extent the issues are related to market needs and do not impact reliability, it would be appropriate for NAESB to define appropriate standards. It is prudent to have standards define the process, not the implementation details. |
| North Carolina Municipal Power Agency Number 1. | | X | | |
| RTO/ISO Standards Review Committee | | X | | |
| ISO-NE | | X | | |
| Ontario – Independent Electricity System Operator | | X | | |
| Hydro-Quebec Trans Energie | X | | System quantities that are required by the market (such as ATC/AFC ) should be defined by NAESB | To the extent the issues are related to market needs and do not impact reliability, it would be appropriate for NAESB to define |

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| | | | | appropriate standards. |
| FRCC | | X | No, it is not necessary, but to the extent some sort of business issues need to be addressed, such as response times for OASIS requests, it should be limited strictly to business practices, and not address reliability issues. | Certain aspects of every transfer capability calculation deal with market needs and may be better addressed via a business practice standard. The DT agrees that such efforts should not address reliability issues. |
| Northeast Power Coordinating Council | X | | ATC/AFC system quantities that are market specific should be addressed by NAESB | To the extent the items are related to market needs and do not impact reliability, it would be appropriate for NAESB to define appropriate standards. |
| Exelon | | X | | |
| MRO<br>*Alliant Energy does not agree with these comments | | X | There may be certain practices that could be considered for a NAESB Business Practice, however compliance with it should be voluntary. | To the extent the issues are related to market needs and do not impact reliability, it would be appropriate for NAESB to define appropriate standards. If a standard is defined, it must be adhered to; voluntary compliance is not an effective way of achieving industry-wide standardization. |

5. Do you agree with the list of entities to which the standard would apply?

| Commenter | Yes | No | Comment | Response |
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| Total: | | | | |
| Total | | | In general, most people felt that MOD-001-0 should apply to one or more additional entities.<br><br>Nearly all commented that the standard should apply to the Transmission Planner, Planning Authority, and Regional Reliability Organization.<br><br>And some that asked for the standard to apply to the Transmission Owner and Reliability Coordinator. | Transmission Service Providers (TSPs) should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.<br><br>ISO/RTOs would be covered to the extend they are TSPs. |
| WPS Resources | X | | | |
| Southern Company Transmission | | X | No. See comment in Question #8. | TSPs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator. |
| Southern Company Generation | | X | RTO/ISOs should be required to provide the same documentation for their assumptions and methods. | TSPs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator. |
| NYISO | X | | | |
| ATC Task Force of NERC | | X | No – Aspects of this standard also should apply to the Transmission Planner, Transmission Owner, Planning Authority, and Regional Reliability Organization.<br><br>In those areas where Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), or other agents, such as Transmission Service Coordinators (TSCs), are involved with ATC, TTC, and AFC calculations for multiple Regions or portions thereof, the role of these entities must be clearly defined. | TSPs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator. |
| North Carolina Municipal Power Agency Number 1. | X | | | |
| RTO/ISO Standards Review Committee | | X | Aspects of this standard would also apply to Transmission Planner, Transmission Owner, Planning Authority, RC and Regional Reliability Organization. | TSPs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator. |

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| ISO-NE | | X | Aspects of this standard will also apply to Transmission Planner and Regional Reliability Organization | TSPs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator. |
| Ontario – Independent Electricity System Operator | | X | Aspects of this standard would also apply to Transmission Planner, Transmission Owner, Planning Authority, RC and Regional Reliability Organization. | TSPs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator. |
| Hydro-Quebec Trans Energie | | X | LSE, PSE, MO, PA, TP | TSPs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator. |
| FRCC | | X | This standard should also apply to the Planning Authority and the Reliability Regions. | TSPs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator. |
| Northeast Power Coordinating Council | | X | Aspects of this standard will also apply to Transmission Planner, Planning Authority and Regional Reliability Organization | TSPs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator. |
| Exelon | X | | | |
| MRO<br>*Alliant Energy does not agree with these comments | | X | Aspects of this standards should also apply to Transmission Planner, Transmission owner, Planning Authority and Regional Reliability Organization. | TSPs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator. |

6. Do you have any other terms that should be included in the definitions?

| Commenter | Yes | No | Comment | Response |
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| Total: | | | Of 14 responses, 3 were "yes", 11 were "no".<br><br>Most entities did not see the need for additional terms to be included in the standard. The ones that did see the need for new terms were mostly focused on better definitions for NATC and RATC. | ATCT agrees that Ultimate Source and Ultimate Sink should be defined.<br><br>ATCT DT feels that Non Recallable ATC and Recallable ATC should remain with NERC |
| WPS Resources | | X | | |
| Southern company – Transmission | | X | | |
| Southern Company Generation | | X | It should be pointed out that this standard should contain consistent definitions, including but not limited to, ATC, AFC, TTC, CBM, and TRM. The definitions should be developed as part of the industry effort of this standard. | ATCT agrees that Ultimate Source and Ultimate Sink should be defined.<br><br>ATCT DT feels that Non Recallable ATC and Recallable ATC should remain with NERC |
| NYISO | | X | | |
| ATC Task Force of NERC Planning Committee | X | | Yes – In the SAR or standard drafting of the proposed ATC/TTC standard, definitions must be established, as necessary, for industry acceptance so that a common language is used in reference to ATC and TTC. In particular, definitions for "flowgate," "flowgate rating," and "Available Flowgate Capability (AFC)" need to be established (See also the fourth paragraph in response to Question 2.) since these terms have never been formally defined by NERC.<br><br>On pages SAR - 4 and SAR – 9, further clarification and direction are needed for the Standard Drafting Team (SDT) concerning definitions. This portion of the SAR is not written in complete sentences and therefore may not be completely understood by those who were not on the LTATF. For example, the SAR lists "Daily, Monthly, Yearly TTC." Does the LTATF wish the Standard Drafting Team to prepare definitions for Daily, Monthly, Yearly TTC and ATC? The SAR says that the TTC and ATC are defined in standard 1E1. These definitions should be repeated here so that it is clear what the SDT should use as a starting point. ATC is defined in the SAR by an equation. Is this to be added to the definition in 1E1 for ATC or is this already included in the previous | ATCT DT agrees with ATC Task Force of Planning Committee regarding flowgate, flowgate rating, and available flowgate capability.<br><br>ATCT agrees that Ultimate Source and Ultimate Sink should be defined<br><br>ATCT DT feels that Non Recallable ATC and Recallable ATC should remain with NERC |

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| | | | definition? Then, Existing Transmission Commitments (ETC) is listed with no directions. Does the LTATF wish ETC to be defined, ETC definition to change, or something else? The SAR needs to be specific as to which definitions the SAR drafting team recommends to be added, deleted, or changed. If changes are needed, the SAR needs to explain what sorts of changes are required. | |
| North Carolina Municipal Power Agency Number 1. | | X | | |
| RTO/ISO Standards Review Committee | | X | | |
| ISO-NE | | X | | |
| Ontario – Independent Electricity System Operator | | X | | |
| Hydro-Quebec Trans Energie | X | X | NATC and RATC .firm or non firm should be defined by NAESB<br><br>Ultimate source and sink have a role in TTC determination and should be included in the NERC standard | The standard should include definitions for these terms. |
| FRCC | | X | | |
| Northeast Power Coordinating Council | X | | NATC and RATC should be defined by NAESB | The standard should include definitions for these terms. |
| Exelon | | X | | |
| MRO<br>*Alliant Energy does not agree with these comments | | X | | |

7. Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?

| Commenter | Yes | No | Comment | Response |
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| Total: | | | All responders felt that no other data elements should be included.<br><br>One responder considers the proposed standard too onerous. | ATCT DT agrees that no other data elements are required. |
| WPS Resources | | X | | |
| Southern Company Transmission | | X | | |
| Southern Company Generation | | X | | |
| NYISO | | X | | |
| ATC Task Force of NERC Planning Committee | | X | No additional data elements | |
| North Carolina Municipal Power Agency Number 1. | | X | | |
| RTO/ISO Standards Review Committee | | X | | |
| ISO-NE | | X | | |
| Ontario – Independent Electricity System Operator | | X | | |
| Hydro-Quebec Trans Energie | | X | The proposed standard is already too much directive and may unduly impose some coordination requirements to some transmission service providers | The drafting team disagrees, the drafting team does not believe that the proposed standard is too directive, and thinks that it would not unduly impose some coordination requirements to some transmission service providers |
| FRCC | | X | | |
| Northeast Power Coordinating Council | | X | | |
| Exelon | | X | | |
| MRO<br>*Alliant Energy does not agree with these comments | | X | | |

8. Do you have any other comments on these proposed standards?

| Commenter | Comment | Response |
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| | In general, most people felt that RTOs/ISOs should not be exempt from the documentation process, and the methodology should gain RRO approval of the methodology.<br><br>Most felt that standardization was not necessary but consistency and transparency was. There were comments that there was not support for a single tool across the industry.<br><br>Nearly all commented that there should be consistency with the RRO Planning Criteria.<br><br>And some that asked for Interconnection variances to the standard for isolated entities | ACTC SAR DT agrees with the general comments, and that the standard would apply to RTOs and ISOs if they are certified as a Transmission Service Provider.<br><br>ATCT SAR DT suggests that for an entity that crosses multiple RRO boundaries could either get approval from each RRO in aggregate or from NERC. |
| WPS Resources | As written, the proposed standards do not require an RTO/ISO to develop and document an AFC/TTC/ATC methodology consistent with the standards. Section B (R1) must include language to ensure that the standard also applies to an RTO/ISO performing AFC/TTC/ATC calculations.<br><br>Throughout the proposed standard, there is not a consistent reference to AFC and TTC/ATC. For example, some areas of the SAR refer only to AFC and other areas refer to TTC/ATC.<br><br>All requirements of the proposed standard should apply to all three quantities, AFC/TTC/ATC. | See general response to comments above.<br><br>The drafting team will word check the proposal to ensure that all three terms, ATC AFC TTC, are used throughout as appropriate. |
| Southern Company Transmission | While this SAR suggests that individual transmission owners and operators within an RTO or ISO may be exempt from developing and documenting a regional methodology for TTC/ATC/AFC determination, we expect that the RTO/ISO would not be exempt from clearly documenting their assumptions and methods. Maintaining this requirement will help to ensure the same transparency exists for the RTO/ISO footprint as in other regions. | See general response to comments above. |
| Southern Company Generation | While this SAR suggests that individual transmission owners and operators within an RTO or ISO may be exempt from developing and documenting a regional methodology for TTC/ATC/AFC determination, we expect that the RTO/ISO would not be exempt from clearly documenting their assumptions and methods. Maintaining this requirement will help to ensure the same transparency exists for the RTO/ISO | See general response to comments above. |

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| | footprint as in other regions. | |
| NYISO | Section R.1.7 - all data listed should be considered confidential and used for the purposes of RC reliability studies.<br><br>Section R.1.7.2 - please clarify what is meant by Generation Dispatch Order and why it is needed?<br><br>Section R.1.7.6 - please explain why this document specifies the use of tool, namely SDX, while other NERC standards such as coordinated operations are not requiring the use of a specific software tool. | The drafting team does not believe that 1.7.6 specifically requires the use of SDX.<br><br>The drafting team agrees that a coordination agreement is not necessary, but would be advantageous, for an exchange of data in 1.7.7, and will review the wording. |
| ATC Task Force of NERC Planning Committee | Yes - The ATC/TTC SAR needs to be reworded to clearly establish the following:<br>1) A Regional ATC/TTC methodology must be developed in conjunction with Regional members.<br>2) All ATC/TTC calculators must abide by the Regional methodology for the Region in which they are members.<br>3) RTOs and ISOs that encompass multiple Regional Reliability Organizations are exempt from abiding by the Regional ATC/TTC methodology provided they have established a single ATC/TTC calculation methodology, in conjunction with their membership, for the entire RTO or ISO. These RTO or ISO methodologies must be consistent with the requirements of the NERC ATC/TTC standard and applicable Regional criteria.<br>4) 4) RTOs and ISOs that are exempt from the Regional methodologies must perform reviews to ensure consistency between the RTO or ISO ATC /TCC calculation methodology and their members' transmission planning and operating criteria. If this requirement is not added, there is no check on the consistency with planning and operating criteria for members who are not under the Regional methodology but under an RTO or ISO ATC/TCC methodology. This requirement will help to ensure that ATC/TTC calculations only incorporate contingencies, TRM components, and CBM for which the systems are reinforced and planned.<br>5) Each RRO must review and approve the RTO or ISO ATC/TTC methodology to ensure that it is consistent | The drafting team agrees that a coordination agreement is not necessary, but would be advantageous, for an exchange of data in 1.7.7, and will review the wording.<br><br>We will look at moving the wording in R3 to the beginning of the section R1.<br><br>The drafting team will consider market aspects.<br><br>The DT will consider the proposed language change in R.1.1 as proposed by the NERC ATC TF |

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| | with the NERC ATC/TTC standard and the RRO's planning and operating criteria. If this requirement is not added, there appears to be no check of an RTO or ISO's ATT/TCC methodology.<br><br>R1.1 – Revise the first sentence to read "Include a narrative explaining how TTC and ATC values are determined and how those values are used in evaluating a transmission service request (TSR), and how the results of the TSR evaluation are made available to customers."<br><br>R1.7.2 – The update frequency should at least be seasonal.<br><br>R3 – This requirement should be combined with R1.1. | |
| North Carolina Municipal Power Agency Number 1. | | |
| RTO/ISO Standards Review Committee | We would suggest the following replace all of R1, not just the first paragraph:<br>"The development of TTC/ATC/AFC methodology is primarily the responsibility of the Transmission Provider, but may be delegated to a Balancing Authority, a Reliability Coordinator. All responsible entities shall develop and document a TTC and ATC/AFC methodology. In the case where the methodology is developed by a designated entity, that methodology document must clearly indicate to which Transmission Providers it applies. That methodology shall be reviewed by the RRO to ensure coordination between the entities within that region and to ensure compliance with this standard. This methodology document shall be available to NERC, the Regions, and the stakeholders in the electricity market."With this change, the language in R1.12 is no longer needed.<br><br>R1.7 - Several items in the set may be considered confidential information that should not be shared with market participants (such as generator outages and generator dispatch orders). These items can be shared with Transmission Service Providers to be used in TTC and ATC calculations but not be released to market participants.<br><br>R1.7.2 - Because of variations on how generation is dispatched in different markets, the drafting team will need to be clear on the generator dispatch information being requested and how it | The drafting team will evaluate rewording the requirement for 1.9, but that we disagree that the SAR is dictating methodologies, but agree that how Long Term rollover rights should be documented.<br><br>We will look at moving the wording in R3 to the beginning of the section R1.<br><br>The drafting team agrees that a coordination agreement is not necessary, but would be advantageous, for an exchange of data in 1.7.7, and will review the wording.<br><br>Generation dispatch orders are required in areas where ATC and TTC are coordinated<br><br>The appendix is used so as to not bind the standard drafting team to any particular formula. |

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| | will be used.<br><br>R1.7.2 - For generators that will be used to determine firm AFC, these should be limited to generators that have already secured firm usage of the transmission system. A transmission service provider should not include generators in the firm AFC calculation that do not have firm transmission service backing them up.<br><br>R1.7.6 - Should a NERC standard reference a tool (such as the SDX) or be more general and apply to the current tool?<br><br>R1.7.7 - We don't understand why AFC will be exchanged only between entities that have coordination agreements. In the Monitoring/Coordination Section of the LTATF Final Report, it states "The Task Force recommends the revision of the existing NERC standards to require the recognition and respect of impacts on external flowgates/paths in AFC/ATC calculations, and the establishment of NERC standards on AFC/ATC coordination." Monitoring other party flowgates was recommendation V. in the AWTTF Short-Term Recommendations.<br><br>R1.9 - The assumption should also include treatment of transmission requests with a status of Study (for both the transmission provider requests and neighboring transmission provider requests) and long-term firm reservations with roll-over rights (for both the transmission provider requests and neighboring transmission provider requests).<br><br>General - The concepts in Appendix will need to be considered in development of the standard. It contains ATC and AFC formula that are not stated in the body of the SAR. | |
| ISO-NE | Comments on the proposed wording:<br>- The current wording of R1 is very confusing, and does not require that RTO/ISOs have a documented methodology. It seems to be trying to acknowledge that some TPs within an RRO may be using an RTO/ISO methodology. We would recommend that while there may be more than one methodology applicable in a region, it should be required that the methodology for every TP in the RRO be available on the RRO website.<br>- R3 is duplicative and should be deleted | Editorial comments will be addressed during the formal standard development phase.<br><br>If a market is not selling service in advance, a regional difference should be identified in the development of the standard.<br><br>We will look to reconcile R3 with R1 |

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| | - We do not understand why Generation Dispatch orders are required for TTC/ATC coordination, Generation Outage coordination should be adequate<br>- It is unclear in the SAR what the intent is of the Appendix. We do not support the definitions shown being included in the standard.<br><br>Recommendation for a Regional Difference:<br>We suggest that a Regional Difference be added to acknowledge that for TPs within a purely financial market, the ATC requirements of this standard are not applicable. However, the requirements associated with TTC continue to be applicable to these TPs. In addition, if these TPs do post ATC, they should be required to post the methodology used to calculate those posted values. | |
| Ontario – Independent Electricity System Operator | IESO would suggest the following replace all of R1, not just the first paragraph:<br>"The development of TTC/ATC/AFC methodology is primarily the responsibility of the Transmission Provider, but may be delegated to a Balancing Authority, a Reliability Coordinator. All responsible entities shall develop and document a TTC and ATC/AFC methodology. In the case where the methodology is developed by a designated entity, that methodology document must clearly indicate to which Transmission Providers it applies. That methodology shall be reviewed by the RRO to ensure coordination between the entities within that region and to ensure compliance with this standard. This methodology document shall be available to NERC, the Regions, and the stakeholders in the electricity market."<br>With this change, the language in R1.12 is no longer required.<br>R1.7 - Several items in the set may be considered confidential information that should not be shared with market participants (such as generator outages and generator dispatch orders). These items can be shared with Transmission Service Providers to be used in TTC and ATC calculations but not be released to market participants.<br>R1.7.2 - Because of variations on how generation is dispatched in different markets, the drafting team will need to be clear on the generator dispatch information being requested and how it will be used.<br>R1.7.2 - For generators that will be used to determine firm | We will look at moving the wording in R3 to the beginning of the section R1.<br><br>The drafting team does not believe that 1.7.6 specifically requires the use of SDX.<br><br>The drafting team agrees that a coordination agreement is not necessary, but would be advantageous, for an exchange of data in 1.7.7, and will review the wording. |

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| | AFC, these should be limited to generators that have already secured firm usage of the transmission system. A transmission service provider should not include generators in the firm AFC calculation that do not have firm transmission service backing them up.<br>R1.7.6 - The IESO does not believe a NERC standard should reference a specific tool (such as the SDX). It should be more general and apply to the current tool(s)?<br>R1.7.7 - IESO doesn't understand why AFC will be exchanged only between entities that have coordination agreements. In the Monitoring/Coordination Section of the LTATF Final Report, it states "The Task Force recommends the revision of the existing NERC standards to require the recognition and respect of impacts on external flowgates/paths in AFC/ATC calculations, and the establishment of NERC standards on AFC/ATC coordination." Monitoring other party flowgates was recommendation V. in the AWTTF Short-Term Recommendations.<br>R1.9 - The assumption should also include treatment of transmission requests with a status of Study (for both the transmission provider requests and neighboring transmission provider requests) and long-term firm reservations with roll-over rights (for both the transmission provider requests and neighboring transmission provider requests).<br><br>General - The concepts in Appendix will need to be considered in development of the standard. It contains ATC and AFC formula that are not stated in the body of the SAR. | |
| Hydro-Quebec Trans Energie | The proposed standard is asking for exhaustive coordination in TTC/ATC/AFC calculation. Outside system boundary coordination requirements are needed in some parts of an Interconnection but could be minimal in other parts. For example, such exhaustive coordination is not required for DC transmission facilities between two asynchronous systems.<br><br>Hydro-Québec TransÉnergie believes that although standardization and coordination of the calculation of ATC, AFC, TTC and the related definitions of TRM and CBM is a valuable goal, it must take into account the specifics of each System. In its own particular case, Hydro-Québec TransÉnergie's system is in fact a distinct Interconnection as it is not synchronized with the Eastern Interconnection. Its ties with the Eastern Interconnection are either controllable (DC | The drafting team will consider different market aspects. |

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| | ties) or radial (generation/load pockets isolated from one system and synchronized with the other). This situation must be taken into account when calculating TTC and ATC. Not being subject to loop flows originating from neighboring Systems and its internal dispatch causing no such loop flows on those Systems, Hydro-Québec TransÉnergie does not have to participate in coordination to calculate flowgate capacities (AFC). Hydro-Québec TransÉnergie already posts its calculation methodology for ATC on its OASIS. The drafting team should include such considerations in the preparation of the relevant standards. | |
| FRCC | Requirement R1.11 states "Ensure that the TTC/ATC calculations are consistent with the TO/TP planning and operating criteria." The standard must be more descriptive about the relationship between these calculations and their consistency with the appropriate planning criteria. The basic criteria utilized for determining acceptable reliability levels should be consistent, but the assumptions and conditions evaluated may be somewhat different to take into account short-term or real-time system conditions as compared to long term planning assumptions. The time horizons for each process will create differences that must be recognized. In many cases, there will be situations that exist in the short term that were not anticipated or modeled in the longer term (> than 1 year) planning cases, such as, planned or unplanned generator outages or line outages. However, the system security must be evaluated with these outages if they extend over the study period when calculating ATC.<br><br>Requirement R1.5 states "Require that ATC values and posting be updated at a minimum frequency to assure proper representation of the transmission system. These values will be made available to stakeholders at a similar frequency". This requirement should not establish a minimum frequency for updating or posting, rather, it should require a minimum frequency of review, with update and posting, only if necessary. It is imperative that the standard establish frequency minimums and timings that are practical and meaningful. Requirement R1.7 specifies minimum update frequencies for 10 items. The standard should be very clear that if values have not changed from the previous posting, such as in the case where there are not any unscheduled transmission outages (R1.7.3), there is not a requirement to post an update. | We agree that differences could occur between operations planning and long-term planning horizons. |

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| | Requirement R1.7 states "Require that the data listed below, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used." Add the words "by transmission providers" to the end of the sentence above. This addition will ensure that there is not a requirement to share this sensitive data with the public. | |
| Northeast Power Coordinating Council | General Comment: It must be noted that the application of ATC, and therefore its derivation, can be significantly different in market-based jurisdictions that do not take physical transmission reservations and those that do. The principles that "An Organization Standard shall neither mandate nor prohibit any specific market structure" and "An Organization Standard shall not preclude market solutions to achieving compliance with that standard" must be maintained. The Standards Drafting Team must be familiar with the market structures in use in North America, to accommodate these variances<br>Items for the Standard Drafting team to consider with respect to the proposed wording:<br>- R1 is very confusing with it's reference to how the methodology must be documented. It seems to leave a hole that does not require RTO/ISOs to post their methodology. While there may be more than one methodology applicable in a region, it should be required that the methodology for every TP in the RRO be available on the RRO website.<br>- R3 is duplicative and should be deleted<br>- We do not understand why Generation Dispatch orders are required for TTC/ATC coordination, Generation Outage coordination should be adequate<br>- It is unclear in the SAR what the intent is of the Appendix. We do not support the definitions shown being included in the standard. | We will look at moving the wording in R3 to the beginning of the section R1.<br><br>The use of the appendix to provide the standard drafting team with the initial thoughts and work of the SAR drafting team, but to not bind them in scope. |
| Exelon | ATC/TTC SAR does not require a RTO or ISO to have a methodology that meets the requirements in this proposed standard. The following wording changes (noted in CAPITALS) to section B-R1 are recommended.<br><br>MOD-001-0 Requirement 1 (R1). Each group of transmission service providers and/or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region shall jointly develop and document a REGIONAL TTC and ATC (which may include the calculation of ATC) methodology. | The standard would apply to RTOs and ISOs if they are certified as a Transmission Service Provider. |

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| | If the transmission service providers and/or AFC/ATC/TTC calculators' AFC, TTC, and ATC values are determined by RTO or ISO, then a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a jointly developed regional methodology. A RTO OR ISO THAT CALCULATES AFC/ATC/TTC IS REQUIRED TO HAVE A WRITTEN METHODOLOGY DOCUMENT THAT MEETS THE REQUREMENTS SPECIFIED IN THIS STANDARD.<br><br>M2 needs to specify that RTOS AND ISOS WILL ALSO BE REQUIRED TO PERFORM THIS REVIEW OF CONSISTENCY WITH PLANNING CRITERIA AND DOCUMENT THE RESULTS. If this requirement is not added, there is no check on the consistency with planning criteria for members who are not under the regional methodology but under a RTO or ISO methodology. | |
| MRO<br>*Alliant Energy does not agree with these comments | On page SAR - 4 Clarification is needed providing the direction for the Standard Drafting Team concerning definitions. This portion of the SAR is not written in complete sentences so that it can be completely understood by those who are not on the LTATF For example, the SAR lists "Daily, Monthly, Yearly TTC". Does the LTATF wish the Standard Drafting Team to prepare definitions for Daily, Monthly, Yearly TTC? The SAR says that the TTC and ATC are defined in standard 1E1. These definitions should be repeated here so that it is clear what the SDT should use as a starting point. ATC is defined in the SAR by an equation. Is this to be added to the definition in 1E1 for ATC or is this already included in the previous definition? Then ATC is listed with no directions. Does the LTATF wish ATC to be defined, ATC definition to change, or something else? The SAR needs to be specific as to which definitions the SAR drafting team thinks needs to be added, deleted, or changed. If changes are needed, the SAR needs to explain what sort of changes are required.<br><br>COMMENTS TO MOD-001-0<br>R1 - Revise the first paragraph to read " Each Transmission Provider shall develop and document a TTC and ATC (may include the calculation of AFC) methodology, and require coordination between the Transmission Providers, with oversight by the respective RRO's." We do not see the need for a RRO region wide methodology, but do see the need for the | The drafting team agrees with MRO and will set forth a minimum set of definitions that must be included in the calculators methodology<br><br>The drafting team believes that MOD-001 clearly addresses the need for an RRO wide methodology.<br><br>The drafting team will consider the proposed language modification by MRO in R.1.1<br><br>The timeframes referenced reflect current requirements for calculation and posting of ATC/TTC by the appropriate regulatory bodies. |

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| | RRO to review the methodology the Transmission Providers use to insure it meets the requirements of this standard. The regional methodology would need to be at a high level even with the exclusion of RTO/ISO members. MRO members include ISO and non-ISO members throughout the MRO region. It would be better for reliability to have the MRO review the Transmission Provider methodology for the items included in the standard then to have a high level regional methodology for non-ISO/RTO members.<br>R1.1 - Revise the first sentence to read "Include a narrative explaining how TTC and ATC values are determined and how those values are used in evaluating a transmission service request (TSR), and how the results of the TSR evaluation are made available to customers."<br>R1.2 - Please clarify what the explanation in the second sentence is meant to accomplish.<br>R1.71 - We would recommend revising the 13 month time frame to 12 months, to reflect seams agreements presently in place.<br>R1.7.2 - The update frequency should at least be seasonal.<br>R1.7.3 - We would recommend revising the 13 month time frame to 12 months, to reflect seams agreements presently in place.<br>R1.9 - Add "(Netting)" after "Transmission Reservations".<br>R1.12 - Revise the article to have the RRO provide authorization for a variance to the regionally approved Transmission Provider's ATC/TTC methodology. Variances to the MRO approval do not require NERC approval.<br>R3 should be combined with R1.1<br>Section C. Measures should be as follows:<br>M1. Each group of transmission service providers within a region, in counjunction with the members of that region, shall jointly develop and implement a procedure to review changes periodically (at least annually) and ensure that that TTC and ATC/AFC calculations and resulting values of member transmission providers comply with the Regionally approved Transmission Provider TTC and ATC methodology, the NERC Planning Standards, and applicable RRO criteria.<br>M2. A review to verify that theAFC/TTC calculations are consistent with the TO's/TP's planning criteria is also required. The procedure used to verify the consistency must also be documented in the report. Documentation of the results of the most current reviews shall be provided to NERC within 30 | |

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| | days of compliance.<br>M3. Each entity responsible for the TTC and ATC methodology, in conjunction with its member(s) and stakeholders, shall have and document a procedure on how stakeholders can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission provider(s), and how these concerns or questions will be addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the stakeholders in the electricity market.<br>M4. The RRO must review and approve the ATC/TTC methodology so as to ensure it is consistent with the RRO's Planning and Operating Criteria. | |

## Questions 1 – 8 apply to ATC/TTC/AFC SAR
## Questions 9 – 16 apply to CBM/TRM SAR

9. Is there a reliability need for the proposed standards?

| Commenter | Yes | No | Comment | Response |
|---|---|---|---|---|
| Total: | | | | The SAR drafting team agrees that there is a reliability need for the standards. |
| WPS Resources | X | | | |
| Southern Company Transmission<br>Marc M. Butts<br>Raymond Vice<br>Keith Calhoun<br>Jim Viikinsalo<br>Doug McLaughlin<br>Jim Griffith<br>Steve Corbin<br>Dean Ulch<br>Mike Robinson<br>Matt Guillebaud | | X | There is a reliability need for communication and coordination of TTC, CBM, and TRM determination, but no reliability need exists for every Transmission Service Provider to utilize the exact same methods to determine these values. | ATCT DT – despite checkbox, answer appears to be yes, but that SCT would like not be bound by the exact same methods. |
| Southern Company Generation<br>Roman Carter<br>Matt Ansley<br>Roger Green<br>Terry Crawley<br>Tom Higgins | | X | There is a reliability need for communication and coordination of TTC, CBM, and TRM determination, but no reliability need exists for every Transmission Service Provider to utilize the exact same methods to determine these values. | ATCT DT – despite checkbox, answer appears to be yes, but that SCG would like not be bound by the exact same methods. |
| NYISO<br>Mike Calimano | X | | | |
| ATC Task Force of NERC Planning Committee<br>Paul B. Johnson – American Electric Power<br>Tomas C. Mielnik – Mid American Energy Co.<br>William Harm – PJM International<br>Ronald F. Szymaczak – Exelon<br>Thomas E. Washburn – Orlando Utilities<br>Lee Westbrook – TXU Electric Del. | X | | Yes - There is a reliability need for the CBM/TRM standard. Please see the comments provided in response to Question 10 below. | |

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| Virginia C. Sulzberger - NERC | | | | |
| North Carolina Municipal Power Agency Number 1.<br>Matt Schull | | | | |
| RTO/ISO Standards Review Committee<br>Anita Lee – AESO<br>William Phillips – MISO<br>Sam Jones – ERCOT<br>Ron Falsetti - IESO<br>Peter Brandien – ISO – NE<br>Karl Tammar – NYISO<br>Bruce Balmat – PJM<br>Charles Yeung – SPP<br>Lisa Szot - CAISO | X | | | |
| ISO-NE<br>Kathleen M. Goodman | X | | | |
| Ontario – Independent Electricity System Operator<br>Ron Falsetti | X | | | |
| Hydro-Quebec Trans Energie<br>Soulier Daniel<br>Victor Bissonnette | X | X | Yes for the TRM use to take into account inaccuracy/uncertainty in TTCs forcasted values.<br><br>No for the CBM and the TRM use to retain transmission capacity for unplanned utilization. System reliability impacted by transmission congestion could be managed by the market through adequate and well coordinated market rules. LSEs should gain firm access to the system to be protected for contingencies by acquiring adequate transmission service from the source to the load, not by CBM and/or TRM. | CBM is needed for reliability, and while that there is a clear need to reserve access from generation to load, whether it is done through an explicit reservation or CBM, is up to the transmission provider and/or appropriate regulatory agency.<br><br>ATCT DT generally agrees for the need for TRM, however TRM should be consistent with your planning methodologies.<br><br>ATCT DT disagrees and think that unplanned utilization (e.g. loop flow) should be part of TRM. |
| FRCC<br>John Odom – FRCC<br>Tom Washburn – OUC<br>Gary Brinkworth – City of Tallahassee<br>Paul Elwing – Lakeland Electric<br>Carter Edge – Southeastern Power Admin.<br>Roger Westphal – Gainesville Regional Utilities<br>Bob Schoneck – Fl. Power & | X | | Reliability must be maintained at all times including accounting for planned outages and unexpected dynamic system conditions, while at the same time providing for ATC/AFC to users of the system. Therefore there is a reliability need for this standard. A transmission system has finite capability and the provision for a transmission reliability margin (TRM) is an important component in determining ATC/AFC and is necessary to take into account such varied system conditions in order to maintain reliability while not overstating the ATC/AFC. | seems to say yes, as does ATCT DT |

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| Light<br>Don McInnis – Fl. Power & Light<br>Kiko Barredo – Fl. Power & Light<br>Paul Graves – Progress Energy FLA<br>Ron Donahey – Tampa Electric Co. | | | | |
| Northeast Power Coordinating Council<br>Guy V. Zito | X | | | |
| Exelon<br>Ronald Szymaczak | X | | | |
| MRO<br>Ken Goldsmith – MRO<br>Al Boesch – NPPD<br>Terry Bilke – MISO<br>Robert Coish – MHEB<br>Dennis Florom – LES<br>Todd Gosnell – OPPD<br>Wayne Guttormson – SPC<br>Jim Maenner - WPS<br>Tom Mielnik – MEC<br>Darrick Moe – WAPA<br>Joe Knight – MRO<br>30 Additional MRO Memebers<br>*Alliant Energy does not agree with these comments | X | | | |

10. Is the calculation and/or withholding of CBM (as opposed to TRM) as an explicit quantity necessary for reliability and should it be part of a reliability standard?

| Commenter | Yes | No | Comment | Response |
|---|---|---|---|---|
| Total: | | | In general, most people felt that withholding of CBM is necessary for reliability, though some areas use zero CBM.<br><br>Some replied that standardization is necessary if CBM is withheld.<br><br>Only one "No" response, which came from Hydro Quebec | The ATCT DT believes that the original intent of CBM was to protect the LSEs within an area and should be a benefit to reliability, but some of the ATCT DT feels that the current processes employed by transmission service providers could actually be a detriment rather than a benefit to reliability.<br><br>A minority opinion white paper has been written on this topic and provided with the ATCT DT information. However, the others on the ATCT DT feel that the calculation of CBM amounts and how they are implemented in an ATC/TTC calculation are reliability issues that belong in the CBM/TRM standard.<br><br>ATCT DT believes that only MOD –006 Section R.1.3 should be sent to NAESB (Procedure for the use of CBM Values). The process under which CBM is released for use by the market may be considered a business practice that could be handled by NAESB.<br><br>CBM will not be required to be withheld. If it is used, a consistent regional (RRO) methodology will be required. |
| WPS Resources | X | | But, only to the extent that the resource adequacy requirement of the CBM region assumes support from external resources AND the transmission system of the CBM region is planned and built to accommodate the CBM amount. | In areas that utilize CBM, consistency between CBM calculation criteria and planning criteria will be required |
| Southern Company Transmission | X | | Availability of CBM is an integral part of overall system reliability for each entity that relies on it as part of its generation adequacy calculations. | CBM will not be required to be withheld, if it is used a consistent regional (RRO) methodology will be required. |
| Southern Company Generation | X | | Availability of CBM is an integral part of overall system reliability for each entity that relies on it as part of its generation adequacy calculations. | CBM will not be required to be withheld, if it is used a consistent regional (RRO) methodology will be required. |
| NYISO | X | | In the operation horizon the NYISO does not use CBM, however, we agree that areas that employ a non-zero CBM should coordinate and document the process. | In areas that utilize CBM, transparency in the calculation methodology of CBM will be required. |
| ATC Task Force of NERC Planning Committee | X | | Yes – Earlier in the development of this industry, there were predominantly local, vertically integrated electric utilities. Each utility built sufficient generation to serve its own load responsibility. Transmission interconnections with neighboring utilities were typically established for one of the following reasons: 1) to minimize duplication of transmission (i.e., tie to neighbor | Agreed. CBM will not be required to be withheld, if it is used a consistent regional (RRO) methodology will be required.<br>Agreed. CBM will not be required to be withheld, if it is used a consistent regional (RRO) methodology will be required to recognize the Reserve Sharing Pools. |

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| | | | for transmission reliability), and 2) an economic decision, to build transmission instead of generation based on the generation reliability criteria for which the utility planned (i.e., tie to neighbor to meet generation reliability criteria). This second reason is the origin of the CBM concept. Transmission interconnections provide each interconnected system with access to its neighbors so that in the event of an extreme generation outage within a utility, the temporarily generation deficient utility could have access to "emergency" generation resources from its interconnected neighbors. CBM is the quantification of this use of the transmission system. Therefore, CBM is an "emergency" use transmission quantity and only exists on the importing system for use only during periods of an emergency generation deficiency when firm transmission service is not available. Just as transmission capacity is preserved for the transmission contingencies for which a utility plans, transmission capacity is also preserved for the generation contingencies for which a utility plans. In either case, the utility customers paid for the transmission capacity that was installed to maintain the reliability level that is planned, via their rates for service.<br><br>Some reserve sharing pools utilize CBM to ensure transfer capability is available for movement of emergency energy. Without CBM, this may not be possible, resulting in significant reliability issues. | |
| North Carolina Municipal Power Agency Number 1. | | | | |
| RTO/ISO Standards Review Committee | X | | Some areas use zero for CBM. If CBM is used, the standardized definitions should be used and amount disclosed. | Agreed. CBM will not be required to be withheld, if it is used a consistent regional (RRO) methodology will be required. |
| ISO-NE | X | | | |
| Ontario – Independent Electricity System Operator | X | | Some areas use zero for CBM. If CBM is used, the standardized definitions should be used and amount disclosed. | In areas that utilize CBM, transparency in the calculation methodology of CBM will be required. |
| Hydro-Quebec Trans Energie | | X | LSEs should gain firm access to the system to be protected for contingencies by acquiring adequate transmission service from the source to the load, not by CBM and/or TRM. | ATCT DT thinks that CBM is needed for reliability, and while that there is a clear need to reserve access from generation to load, whether it is done through an explicit reservation or CBM, is up to the transmission provider and/or appropriate regulatory agency. |
| FRCC | X | | Since CBM is an "implied" reservation of a portion of the transmission capability it is important to include it an | In areas that utilize CBM, inclusion in ATC calculations will be required. |

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| | | | ATC calculations to ensure reliability. | |
| Northeast Power Coordinating Council | X | | While not all TPs use CBM, those that do use it for reliability reasons. | Agreed. CBM will not be required to be withheld, if it is used a consistent regional (RRO) methodology will be required. |
| Exelon | X | | Earlier in the development of this industry, there were predominately 'local' vertically integrated electric utilities. Each utility built sufficient generation to serve its own load responsibility. Transmission interconnections with neighboring utilities were typically established for one of the following reasons:<br>First, to minimize duplication of transmission (i.e. tie to neighbor for transmission reliability.)<br>Second, was an economic decision to build transmission instead of generation based on the generation reliability criteria the utility planned for (i.e. tie to neighbor to meet generation reliability criteria.)<br>This second reason is the origin of the CBM concept. Transmission interconnections provide each interconnected system with access to their neighbors so that in the event of an extreme generation outage within a utility, that temporarily generation deficient utility could have access to 'emergency' generation resources from their interconnected neighbors. CBM is the quantification of this use of the transmission system. Therefore CBM is an 'emergency' use transmission quantity and only 'exists' on the importing system for use only during periods of an emergency generation deficiency when firm transmission service is not available. Just as transmission capacity is preserved for the generation contingencies a utility planned for, transmission capacity is also preserved for the generation contingencies that are planned for. In either case, the utility customers paid for the transmission capacity that was installed to maintain the reliability level that is planned for, via their rates for service. | Agreed. CBM will not be required to be withheld, if it is used a consistent regional (RRO) methodology will be required. |
| MRO<br>Alliant Energy does not agree with these comments | X | | Some reserve sharing pools utilize CBM to insure transfer capability is available for movement of emergency energy. Without CBM, this may not be possible resulting in significant reliability issues. | Agreed. CBM will not be required to be withheld, if it is used a consistent regional (RRO) methodology will be required.<br>Agreed. CBM will not be required to be withheld, if it is used a consistent regional (RRO) methodology will be required to recognize the Reserve Sharing Pools. |

11. Do you agree with the scope of the proposed standard?

| Commenter | Yes | No | Comment | Response |
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| Total: | | | In general, most companies/organizations that commented on the SAR agreed with the scope of the proposed standards. Only three commenters did not agree with the scope. These were Hydro Quebec Trans Energie (agreed and disagreed), Southern Company Generation, and Southern Company Transmission.<br><br>Most felt that the scope of the proposed standard was acceptable.<br><br>Nearly all elected not to comment except for a statement of agreement with the scope of the proposed standard. | The majority of the drafting team agrees with the scope. |
| WPS Resources | X | | | |
| Southern Company Transmission | | X | As with the SAR for MOD-001-0, the scope of this SAR goes beyond what is required for system reliability. There is no reliability need to prescribe in detail how each entity should calculate either TRM or CBM. There is a need to ensure transparency in the methodology used by each entity, but not in the specific components of the calculation. | ATCT DT feels that the level of detail and data elements remain to be specified, but that coordination and communication procedures should be the same.<br><br>ATCT DT recognizes that different regulatory regimes might impact what is determined to be needed for CBM and TRM. |
| Southern Company Generation | | X | As with the SAR for MOD-001-0, the scope of this SAR goes beyond what is required for system reliability. There is no reliability need to prescribe in detail how each entity should calculate either TRM or CBM. There is a need to ensure transparency in the methodology used by each entity but not in the specific components of the calculation. | ATCT DT feels that the level of detail and data elements remain to be specified, but that coordination and communication procedures should be the same.<br><br>ATCT DT recognizes that different regulatory regimes might impact what is determined to be needed for CBM and TRM. |
| NYISO<br>Mike Calimano | X | | | |
| ATC Task Force of NERC Planning Committee | X | | Yes – The scope of the standard is sufficient for the industry at this time. | |
| North Carolina Municipal Power Agency Number 1. | | | | |
| RTO/ISO Standards Review Committee | X | | | |
| ISO-NE | X | | | |
| Ontario – Independent Electricity System Operator | X | | | |
| Hydro-Quebec Trans Energie | X | X | see 9. in addition over utilization of TRM and CBM may lead to limit open access to the system | ATCT DT - Section R1.3 of MOD-008 of the SAR lists the components of uncertainty that can be accounted for in TRM. |

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| | | | | There is no component in TRM and CBM capacity that is set aside for unplanned utilization. While TRM may become available to the market as Non-Firm Transmission service, it is not set aside with those intentions. The section also notes that "Any additional components of uncertainty shall benefit the interconnected transmission system, as a whole...." When analyzing this section we need to be aware of how much the TRM and CBM definitions are limiting open access to the system. A balance needs to be found between adequate protection from uncertainty in the system and allowing open access to all parties involved.<br><br>ATCT DT disagrees and thinks that unplanned utilization (e.g. loop flow) should be part of TRM. Please provide further clarification on what HQ considers to be included in "unplanned utilization" |
| FRCC | X | | | |
| Northeast Power Coordinating Council | X | | | |
| Exelon<br>Ronald Szymaczak | X | | | |
| MRO<br>*Alliant Energy does not agree with these comments | X | | | |

12. Are there aspects of the proposed standard you believe should be developed as a business practice through NAESB?
Note: NAESB has a proposal for companion business practice - R05004)

| Commenter | Yes | No | Comment | Response |
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| Total: | | | In general, most people felt that there are no aspects of the proposed standard that should be developed as a business practice through NAESB.<br><br>And some that asked for the CBM calculation and/or use (MOD-006-0) to be a NAESB business practice. | ATCT DT believes that only MOD –006 Section R.1.3 should be sent to NAESB (Procedure for the use of CBM Values). The process under which CBM is released for use by the market may be considered a business practice that could be handled by NAESB.<br><br>However, the calculation of CBM amounts and how they are implemented in an ATC/TTC calculation are reliability issues that belong in the CBM/TRM standard. |
| WPS Resources | X | | NAESB business practice R05004. | ATCT DT believes that only MOD –006 Section R.1.3 should be sent to NAESB (Procedure for the use of CBM Values). The process under which CBM is released for use by the market may be considered a business practice that could be handled by NAESB. However, the calculation of CBM amounts and how they are implemented in an ATC/TTC calculation are reliability issues that belong in the CBM/TRM standard. |
| Southern Company ransmission | | X | | |
| Southern Company Generation | | X | | |
| NYISO | | X | | |
| ATC Task Force of NERC Planning Committee | X | | Yes – The process under which CBM is used may be considered a business practice that could be handled by NAESB. However, the calculation of CBM amounts and how they are implemented in an ATC/TCC calculation are reliability issues that belong in the CBM/TRM standard | ATCT DT believes that only MOD –006 Section R.1.3 should be sent to NAESB (Procedure for the use of CBM Values). The process under which CBM is released for use by the market may be considered a business practice that could be handled by NAESB. However, the calculation of CBM amounts and how they are implemented in an ATC/TTC calculation are reliability issues that belong in the CBM/TRM standard. |
| North Carolina Municipal Power Agency Number 1. | | | | |
| RTO/ISO Standards Review Committee | | X | | |
| ISO-NE | | X | | |
| Ontario – Independent Electricity System Operator | | X | | |
| Hydro-Quebec Trans Energie | X | | System reliability impacted by transmission congestion could be managed by the market through adequate and well coordinate market rules | The Drafting Team agrees. However, this approach requires liquid and transparent markets, which do not exist in some regions. The Drafting Team will look for a solution that can be applied to all market types. |

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| | | | | ATCT DT believes that only MOD –006 Section R.1.3 should be sent to NAESB (Procedure for the use of CBM Values). The process under which CBM is released for use by the market may be considered a business practice that could be handled by NAESB. However, the calculation of CBM amounts and how they are implemented in an ATC/TTC calculation are reliability issues that belong in the CBM/TRM standard. |
| FRCC | | X | No, it is not necessary, but to the extent some sort of business issues need to be addressed, such as response times for OASIS requests, it should be limited strictly to business practices, and not address reliability issues. Additionally, TRM is a reliability quantity and therefore would be inappropriate for NAESB to have a parallel standard. | ATCT DT believes that only MOD –006 Section R.1.3 should be sent to NAESB (Procedure for the use of CBM Values). The process under which CBM is released for use by the market may be considered a business practice that could be handled by NAESB.<br><br>However, the calculation of CBM amounts and how they are implemented in an ATC/TTC calculation are reliability issues that belong in the CBM/TRM standard. |
| Northeast Power Coordinating Council | | X | | |
| Exelon | | X | | |
| MRO<br>*Alliant Energy does not agree with these comments | | X | There may be certain practices that could be considered for a NAESB Business Practice, however compliance with it should be voluntary. | ATCT DT believes that only MOD –006 Section R.1.3 should be sent to NAESB (Procedure for the use of CBM Values). The process under which CBM is released for use by the market may be considered a business practice that could be handled by NAESB. However, the calculation of CBM amounts and how they are implemented in an ATC/TTC calculation are reliability issues that belong in the CBM/TRM standard. |

13. Do you agree with the list of entities to which the standard would apply?

| Commenter | Yes | No | Comment | Response |
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| Total: | | | In general, most people felt that additional entities to which the standard would apply needed to be added to the list.<br><br>Nearly all responders (7/9) who thought additional entities should be added commented that the following entities were appropriate to add – Planning Authority, Regional Reliability Organization and Transmission Planners<br><br>And some responders who thought additional entities should be added commented that the following additional entities be added – Transmission Owner (4/9), Reliability Coordinator (1/9), Load Serving Entity (1/9), Purchasing-Selling Entity (1/9), Market Operator (1/9), RTO/ISO (1/9). | This standard would apply to whatever entity that calculates CBM/TRM, and could apply to TSP, Planning Authority, Regional Reliability Organization and Transmission Planners |
| WPS Resources | X | | | |
| Southern Company Transmission | | X | Similar to the comments supplied in response to Question 8, we expect that all regions will be expected to clearly document their assumptions and methods, regardless of operational or organizational structure, in order to ensure transparency. | The drafting team agrees with the need for transparency. |
| Southern Company Generation | | X | RTO/ISOs should be required to provide the same documentation for their assumptions and methods. | DT agrees addition of suggested additional entities is appropriate.<br><br>RTO/ISOs would be covered if they are registered as Transmission Service Providers. |
| NYISO | X | | | |
| ATC Task Force of NERC Planning Committee | | X | No – Aspects of this standard also should apply to the Transmission Planner, Transmission Owner, Planning Authority, and Regional Reliability Organization.<br><br>In those areas where Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), or other agents, such as Transmission Service Coordinators (TSCs), are involved with ATC, TTC, and AFC calculations for multiple Regions or portions thereof, the role of these entities must be clearly defined. | DT agrees addition of suggested additional entities is appropriate.<br><br>RTO/ISOs would be covered if they are registered as Transmission Service Providers. |
| North Carolina Municipal Power Agency Number 1. | | | | |
| RTO/ISO Standards Review | | X | Aspects of this standard should also apply to | DT agrees addition of suggested additional entities is appropriate. |

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| Committee | | | Transmission Planner, Transmission Owner, Planning Authority, RC and Regional Reliability Organization | |
| ISO-NE | | X | Aspects of this standard will also apply to Transmission Planner and Regional Reliability Organization | DT agrees addition of suggested additional entities is appropriate. |
| Ontario – Independent Electricity System Operator | | X | Aspects of this standard should also apply to Transmission Planner, Transmission Owner, Planning Authority, RC and Regional Reliability Organization | DT agrees addition of suggested additional entities is appropriate. |
| Hydro-Quebec Trans Energie | | X | LSE, PSE, MO, PA, TP | DT agrees addition of suggested additional entities is appropriate. |
| FRCC. | | X | This standard should also apply to the Planning Authority and the Reliability Regions. | DT agrees addition of suggested additional entities is appropriate. |
| Northeast Power Coordinating Council | | X | Aspects of this standard will also apply to Transmission Planner, Planning Authority and Regional Reliability Organization | DT agrees addition of suggested additional entities is appropriate. |
| Exelon | X | | | |
| MRO<br>*Alliant Energy does not agree with these comments | | X | Aspects of this standards should also apply to Transmission Planner, Transmission Owner, Planning Authority, and Regional Reliability Organization. | DT agrees addition of suggested additional entities is appropriate. |

14. Do you have any other terms that should be included in the definitions?

| Commenter | Yes | No | Comment | Response |
|---|---|---|---|---|
| Total: | | | In general, most people felt that no additional terms should be included in the definition(s) | The drafting team agrees that no additional terms are required, except as noted below. |
| WPS Resources | | X | | |
| Southern Company Transmission | X | | Please define "Calculation Model" as described in requirement R1.7.9. | Will refer this to standard drafting team |
| Southern Company Generation | X | | Please define "Calculation Model" as described in requirement R1.7.9. | Will refer this to standard drafting team |
| NYISO | | X | | |
| ATC Task Force of NERC Planning Committee | | X | No – In the SAR or standard drafting of the proposed CBM/TRM standard, definitions must be established, as necessary, for industry acceptance so that a common language is used in reference to CBM and TRM | Will refer this to standard drafting team |
| North Carolina Municipal Power Agency Number 1. | | | | |
| RTO/ISO Standards Review Committee | | X | | |
| ISO-NE | | X | | |
| Ontario – Independent Electricity System Operator | | X | | |
| Hydro-Quebec Trans Energie | | X | | |
| FRCC | | X | | |
| Northeast Power Coordinating Council | | X | | |
| Exelon | | X | | |
| MRO<br>*Alliant Energy does not agree with these comments | | X | | |

15. Do you have any other data elements that should be included in the coordination and communication of the calculation of CBM/TRM?

| Commenter | Yes | No | Comment | Response |
|---|---|---|---|---|
| Total: | | | All agreed that no additional data elements should be required. (North Carolina Municipal Power Agency Number 1 did not respond) | The drafting team does not see a need for any additional data elements. |
| WPS Resources | | X | | |
| Southern Company Transmission | | X | | |
| Southern Company Generation | | X | | |
| NYISO | | X | | |
| ATC Task Force of NERC Planning Committee | | X | No additional data elements. | |
| North Carolina Municipal Power Agency Number 1. | | | | |
| RTO/ISO Standards Review Committee | | X | | |
| ISO-NE | | X | | |
| Ontario – Independent Electricity System Operator | | X | | |
| Hydro-Quebec Trans Energie | | X | | |
| FRCC | | X | | |
| Northeast Power Coordinating Council | | X | | |
| Exelon | | X | | |
| MRO<br>*Alliant Energy does not agree with these comments | | X | | |

16. Do you have any other comments on these proposed standards?

| Commenter | Comment | Response |
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| | Generally most agreed that the SAR needs to state that to the extent that RTOs/ISOs are transmission service providers, they also need to also document their methodology with RRO approval | ATCT DT – where a TSP crosses Regional boundaries, all RROs must approve the methodology. ATCT SAR DT suggests that for an entity that crosses multiple RRO boundaries could either get approval from each RRO in aggregate or from NERC.<br><br>ATCT DT – will remove references to RTOs/ISOs because they are not in the functional model, howeverthey could be acting as a TSP with respect to these standards<br><br>ATCT DT – each TSP's methodologies will have to meet their respective Regional criteria.<br><br>CBM will not be required to be withheld, if it is used a consistent regional (RRO) methodology should be required. |
| WPS Resources | As written, the proposed standards do not require an RTO/ISO to develop and document a CBM/TRM methodology consistent with the standards. Section R1 of MOD-004-00 must inlcude language to ensure that the standard also applies to an RTO/ISO performing CBM/TRM calculations.<br><br>Within section R1.5 (note numbering error in this section of the SAR) of the CBM methodology (allocation of CBM to interfaces), the methodology should require the specification and rational for the selection of source and sink points to simulate the import of the CBM amount, if a simulation is performed. The source and sink points must be consistent with those used by the transmission owner/service provider in their CBM planning studies.<br><br>The CBM/TRM SAR should include a requirement that the methodology specify how CBM/TRM is incorporated in the AFC/ATC/TTC calculations (firm, nonfirm, or both). If CBM/TRM is applied within a market structure that utilizes a security constrained centrally dispatch system (locational marginal pricing), the SAR should require the that CBM/TRM methodology specify how it is applied in financial transmission rights models, day-ahead models, and real-time models. | ATCT DT – where a TSP crosses Regional boundaries, all RROs must approve the methodology<br><br>ATCT DT – will remove references to RTOs/ISOs because they are not in the functional model, howeverthey could be acting as a TSP with respect to these standards<br><br>ATCT DT – each TSP's methodologies will have to meet their respective Regional criteria. |
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| Southern Company Transmission | If a standard is developed that extends beyond the basic assurance of transparency, any resulting method should only mandate that certain guiding principles be considered in the determination of TRM and CBM - rather than mandate that a prescriptive set of calculations be made. Furthermore, each entity responsible for the generation adequacy of their system should be the one to determine how best to consider their own internal generation for use in the determination of an appropriate CBM value for that specific system. | ATCT DT - the current and proposed versions of MOD 4 state that a CBM methodology be developed within an RRO. If options are provided in the regional methodology, each TSP must document which option is being used. |
| Southern Company Generation | If this standard is developed beyond the transparency issue, the methodology should only mandate that certain guiding principles be considered in the determination of TRM and CBM and not that a industry-wide prescriptive set of calculations be made. Also it should be up to each entity with responsibility for their own system reliability and generation adequacy on how internal generation should be considered in the determination of CBM and thus generation adequacy within their system. | ATCT DT - the current and proposed versions of MOD 4 state that a CBM methodology be developed within an RRO. If options are provided in the regional methodology, each TSP must document which option is being used. |
| NYISO | | |
| ATC Task Force of NERC Planning Committee | Yes – The CBM/TRM SAR needs to be reworded to clearly establish the following:<br>1) A Regional CBM/TRM methodology must be developed in conjunction with Regional members.<br>2) All entities calculating CBM and/or TRM must abide by the Regional methodology for the Region in which they are members.<br>3) RTOs and ISOs that encompass multiple Regional Reliability Organizations are exempt from abiding by the Regional CBM/TRM methodologies provided they have established a single CBM and/or TRM calculation methodology, in conjunction with their membership, for the entire RTO or ISO. These RTO or ISO methodologies must be consistent with the requirements of the NERC CBM/TRM standard and applicable Regional criteria.<br>4) RTOs and ISOs that are exempt from the Regional methodologies must perform reviews to ensure consistency between the RTO or ISO CBM and/or TRM calculation methodologies and their members' transmission planning, generation planning, and operating criteria. If this requirement is not added, there is no check on the consistency with planning and operating criteria for members who are not under the Regional methodology but under an RTO or ISO CBM | ATCT DT – will remove references to RTOs/ISOs because they are not in the functional model however, and they could be acting as a TSP with respect to these standards<br><br>The drafting team will forward these comments to the standards drafting team for possible use during the detailed standards drafting process.<br><br>ATCT DT – for those methodologies include N-1 loss of a unit in TRM, CBM should not also include the loss of that unit, to avoid double counting. |

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| | and/or TRM methodology.<br>5) In addition, the text in section R1 of the SAR needs to be revised to clarify that the following reviews are to be performed by the RRO. First, each RRO needs to review the CBM and/or TRM calculations of transmission providers under the Regional methodology to ensure they are adhering to the Regional methodology. Second, each RRO must review and approve the RTO and ISO CBM and/or TRM methodologies to ensure they are consistent with the NERC CBM/TRM standard and the RRO's planning and operating criteria. Finally, the RRO is responsible for ensuring that TRM calculations performed by transmission service providers, regardless of what methodology they are under, are consistent with the individual transmission owner's planning criteria.<br><br>COMMENTS TO MOD-004-0<br>R1.2 – In bullets 1 and 2, the word "must" should be deleted. It is not necessary.<br>Under the present article number R1.7 – Clarify what the objective is for the "simultaneous application of CBM and TRM." Is this intended to make sure that reserves are not double counted?<br>COMMENTS TO MOD –008-0<br>R1.7 – Clarify what the objective is for the "simultaneous application of CBM and TRM." Is this intended to make sure that reserves are not double counted?<br>COMMENTS TO MOD- 009-0<br>R1.4 – Combine this article into R1.3.<br>R4 – Delete, as it is included in the revised R1.1. | |
| North Carolina Municipal Power Agency Number 1. | | |
| RTO/ISO Standards Review Committee | COMMENTS TO MOD-004-0 and MOD-008-0<br>R1 - References to having a single regional CBM methodology and TRM methodology should be removed along with references to exceptions for entities that are members of an RTO or an ISO.<br>R.1.6 - To the extent generators that are not committed to serve load inside the transmission provider's system are considered in the CBM requirement determination, there should be CBM preserved on impacted flowgates for the use of this | These details will be forwarded to the Standard drafting team when it is formed.<br><br>The ATDT DT suggests that the TSP use the best information available to them (i.e. confirmed or requested transmission service/no service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology. |

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| | generation.<br>There are two R1.4, R1.5 and R1.6.<br>R1.8 - CBM should not be used in place of maintaining either minimum planning reserves or to compensate for poor generator maintenance practices.<br>General - When establishing CBM import area boundaries, there is an explicit assumption that all generators can serve all load within the boundary (with no constraints). As part of the description of the CBM calculation process, it should describe the basis for establishing the CBM import area boundaries. | |
| ISO-NE | Comments on the proposed wording:<br>- R1 of MOD-004 and MOD-008 are confusing and do not require an ISO/RTO to post their methodology. While there may be more than one methodology applicable in a region, it should be required that the methodology for every TP in the RRO be available on the RRO website<br>- R1.8.1 MOD-008 implies that TRM is set as a fixed amount which must be maintained through time, since entities would be required to "plan and reinforce the transmission system for the amount of TRM being preserved". We feel that this is an inappropriate requirement, since TRM represents a variable quantity based on known system conditions plus uncertainty.<br>- R1.8.2 of MOD-008 is not related to item 1.8 and should be moved in the text to be before and applicable to all R1.x requirements. | ATCT DT - MOD 4 already states that a CBM methodology be developed within an RRO. If options are provided in the regional methodology, each TSP must document which option is being used.<br><br>The SAR drafting team agrees that TRM not necessarily be a fixed amount maintained through time.<br><br>The standard drafting team should consider language changes to clarify. |
| Ontario – Independent Electricity System Operator | COMMENTS TO MOD-004-0 and MOD-008-0<br>R1 - References to having a single regional CBM methodology and TRM methodology should be removed along with references to exceptions for entities that are members of an RTO or an ISO.<br>R.1.6 - To the extent generators that are not committed to serve load inside the transmission provider's system are considered in the CBM requirement determination, there should be CBM preserved on impacted flowgates for the use of this generation.<br>Please note the numbering error. There are two R1.4, R1.5 and R1.6.<br>R1.8 - CBM should not be used in place of maintaining either minimum planning reserves or to compensate for poor generator maintenance practices.<br>General - When establishing CBM import area boundaries, there is an explicit assumption that all generators can serve all load within the boundary (with no constraints). As part of the | ATCT DT - the current and proposed versions of MOD 4 state that a CBM methodology be developed within an RRO. If options are provided in the regional methodology, each TSP must document which option is being used.<br>ATCT DT – The ATDT DT suggests that the TSP use the best information available to them (i.e. confirmed or requested transmission service/no service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology.<br><br>The ATCT agrees CBM should not replace “poor resource planning or maintenance”<br>ATCT DT methodology should define how CBM boundaries are defined, as long as those boundaries are consistent with the way the system is planned and used for other considerations, such as calculation of ATC, TTC |

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| | description of the CBM calculation process, it should describe the basis for establishing the CBM import area boundaries. | |
| Hydro-Quebec Trans Energie | The proposed standard is asking for exhaustive coordination in TRM calculation. Outside system boundary coordination requirements are needed in some parts of an Interconnection but could be minimal in other parts. For example, such exhaustive coordination is not required for DC transmission facilities between two asynchronous systems. | The SAR drafting team will recommend to the standard drafting team that it consider differences in market structures. |
| FRCC | "MOD-008-1 R1.5.1 Any variances must also be approved by NERC or its designate. Delete this requirement. Variances should be approved by the Regional Reliability Organizations, not NERC, since the RROs have an approved methodology." | The SAR drafting team will forward this comment to the standard drafting team.<br><br>However, the drafting team believes that while an RRO can allow for flexibility in implementing methodologies, NERC would have to approve variances.<br><br>In a Region wide interconnection a regional variance could be rebuttably presumed to be correct. |
| Northeast Power Coordinating Council | Items for the Standard Drafting team to consider with respect to the proposed wording:<br>- R1 of MOD-004 and MOD-008 seem confusing and not to require an ISO/RTO to post their methodology. While there may be more than one methodology applicable in a region, it should be required that the methodology for every TP in the RRO be available on the RRO website<br>- R1.8.1 MOD-008 implies that TRM is set as a fixed amount which must be maintained through time, since entities would be required to "plan and reinforce the transmission system for the amount of TRM being preserved". We feel that this is an inappropriate requirement, since TRM represents a variable quantity based on known system conditions plus uncertainty.<br>- R1.8.2 of MOD-008 is not related to item 1.8 and should be moved in the text to be before and applicable to all R1.x requirements.<br>In Summary, NPCC concerns are as follows-<br>a) Québec Area is not synchronously interconnected with the rest of the Eastern Intercommunion thus i) coordination requirements are limited within its synchronous system, ii) ultimate source and sink are limited within its synchronous system<br>b) NY's, NE's, IESO 's transmission commitments are not based point to point transmission reservations in both operating and planning horizon thus posting requirement will not include | ATCT DT - MOD 4 already states that a CBM methodology be developed within an RRO. If options are provided in the regional methodology, each TSP must document which option is being used.<br><br>The ATDT DT suggests that the TSP use the best information available to them (i.e. confirmed or requested transmission service/no service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology.<br><br>The ATCT agrees CBM should not replace poor resource planning or maintenance<br><br>ATCT DT methodology should define how CBM boundaries are defined, as long as those boundaries are consistent with the way the system is planned and used for other considerations, such as calculation of ATC, TTC, |

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| | ATC based on physical reservation and we believe that ATC is a market based quantity.<br>c) CBM is more or less a physical reservation made, at no cost, by LSEs within the boundaries of the TP's system. Therefore for some members of NPCC, because they have market based systems and are not using physical reservations, feel a standard NERC Standards for CBM is not necessary.<br>d) Some of NPCC's Areas have confidentiality issues especially with Generator outage schedules and we are asking the drafting team to be cognizant of these and respect this confidentiality. | |
| Exelon | CBM/TRM SAR does not require a RTO or ISO to have a methodology that meets the requirements in this proposed standard. The following word changes (noted in CAPITALS) to section R1 of the CBM portion are recommended -<br>R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region shall jointly develop and document a REGIONAL CBM methodology. This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.<br>If a RRO's members CBM values are determined by a RTO or ISO, then a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a jointly developed regional methodology. A RTO OR ISO THAT CALCULATES CBM AND OR TRM IS REQUIRED TO HAVE A WRITTEN METHODOLOGY DOCUMENT THAT MEETS THE REQUIREMENTS SPECIFIED IN THIS STANDARD.<br>M4 needs to specify that THE RRO MUST REVIEW AND APPROVE THE RTO OR ISO CBM METHODOLOGY TO ENSURE IT IS CONSISTENT WITH THE RRO'S PLANNING ABD OPERATING CRITERIA. If this requirement is not added there appears to be no check of a RTO or ISO' ATC/TTC methodology.<br>CBM/TRM SAR does not require a RTO or ISO to have a methodology that meets the requirements in this proposed standard. The following wording changes (noted in CAPITALS) to section R1 of the TRM portion are recommended :<br>R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with | ATCT DT – will remove references to RTOs/ISOs because they are not in the functional model however, and they could be acting as a TSP with respect to these standards<br><br>The drafting team will forward these comments to the standards drafting team for possible use during the detailed standards drafting process. |

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| | the members of that region in conjunction with its members, shall jointly develop and document a REGIONAL TRM methodology. This methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. If a RRO's members TRM values are determined by a RTO or ISO, than a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a regional methodology. A RTO OR ISO CALCULATES CBM AND OR TRM IS REQUIRED TO HAVE A METHODOLOGY DOCUMENT THAT MEETS THE REQUIREMENTS SPECIFIED IN THIS STANDARD.<br>In addition, the text in section R1 of the SAR needs to be revised to clarify that the following reviews are done by the RRO. First, the RRO needs to review the calculations of transmission providers under the regional methodology to ensure they are adhering to the regional methodology.<br>Second, the RRO must review the transmission service provider(s)' not under the regional methodology to ensure that their methodology is consistent with the RRO's Planning Criteria. Finally, the RRO is responsible for ensuring that TRM calculations done by transmission service providers', regardless of what methodology they are under, are consistent with the individual TOs planning criteria. The following wording changes noted in CAPITALS are recommended:<br>The RRO must review and approve the METHODOLOGY OF transmission service provider(s)' NOT UNDER THE REGIONAL methodology to ensure it is consistent with the RRO's Planning Criteria. The RRO is responsible for ensuring that TRM calculations are consistent with the individual TOs planning criteria. | |
| MRO<br>*Alliant Energy does not agree with these comments | COMMENTS TO MOD-004-0<br>R1 - Revise the first paragraph to read " Each Transmission Provider shall develop and document a CBM methodology, and require coordination between the transmission providers, with oversight by the respective RRO's." We do not see the need for a RRO region wide methodology, but do see the need for the RRO to review the methodology the Transmission Providers use to insure it meets the requirements of this standard. The regional methodology would need to be at a high level even with the exclusion of RTO/ISO members. For example the MRO members | While an RRO can allow for flexibility in implementing methodologies, NERC would have to approve variances.<br>In a Region wide interconnection a regional variance could be rebuttably presumed to be correct.<br><br>ATCT DT – for those methodologies include N-1 loss of a unit in TRM, CBM should not also include the loss of that unit, to avoid double counting.<br><br>The SAR drafting team will forward the other comments to the standard drafting team for consideration during the formal standard drafting process. |

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| | include ISO and non-ISO members throughout the MRO region. It would be better for reliability to have the MRO review the Transmission Provider methodology for the items included in the standard than to have high-level regional methodology for non-ISO/RTO members.<br>R1.2 - In bullets 1 and 2 the word "must" should be deleted. It is not necessary.<br>The article numbering after R1.6 is in error. It drops back to R1.4, when it should be R1.7.<br>Under present article number R1.4, Revise the first sentence to "Describe the formal process and rationale for the RRO to grant any variances to an individual transmission provider's regionally approved CBM Methodology." R1.6.1 should be deleted. The RRO approves variances.<br>Under the present article number R1.7 - Clarify what the objective is for the "simultaneous application of CBM and TRM." Is this intended to make sure that reserves are not double counted?<br>It is not stated if Measures M1 and M2 are kept or not. Please confirm that they are still in force.<br>COMMENTS TO MOD-005-0<br>R1 - Revise the first sentence to read "Each RRO in conjunction with its members, shall develop and implement a procedure to review changes (at least annually) to the CBM calculations and the resulting values of member Transmission Service Providers."<br>R1.3 - We believe R1.3.1 should be incorporated into the standard.<br>COMMENTS TO MOD-006-0<br>We are not opposed to making this standard a Business Practice, as long as the Business Practice is voluntary.<br>COMMENTS TO MOD-008-0<br>R1 - Revise the first sentence of the paragraph to read " Each Transmission Provider in a region shall develop and document, in conjunction with the members of the region, a TRM methodology, and require coordination between the transmission providers, with oversight by the respective RRO's." We do not see the need for a RRO region wide methodology, but do see the need for the RRO to review the methodology the Transmission Providers use to insure it meets the requirements of this standard. The regional methodology would need to be at a high level even with the exclusion of RTO/ISO members. For example the MRO | |

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| | members include ISO and non-ISO members throughout the MRO region. It would be better for reliability to have the MRO review the Transmission Provider methodology for the items included in the standard than to have high-level regional methodology for non-ISO/RTO members.<br>R1.3.10 should be renumbered to R1.3.9. The article that was numbered R1.3.9 should be placed at the end of the list and not have a number.<br>R1.5 - Revise the first sentence to "Describe the formal process and rationale for the RRO to grant any variances to an individual transmission provider's regionally approved TRM Methodology." R1.5.1 should be deleted. The RRO approves variances.<br>R1.7 - Clarify what the objective is for the "simultaneous application of CBM and TRM." Is this intended to make sure that reserves are not double counted?<br>COMMENTS TO MOD-009-0<br>R1 - Revise the first sentence of the paragraph to read " The RRO in a region shall develop and document, in conjunction with the members of the region, a procedure to, at least annually, review the TRM calculations and the resulting values of member transmission providers, to ensure that they comply with the regionally approved transmission provider methodologies." We do not see the need for a RRO region wide methodology, but do see the need for a region-wide process to review the methodology the Transmission Providers use to insure it meets the requirements of this standard. The regional methodology would need to be a high level even with the exclusion of RTO/ISO members. For example the MRO members include ISO and non-ISO members throughout the MRO region. It would be better for reliability to have the MRO review the Transmission Provide methodology for the items included in the standard than to have high-level regional methodology for non-ISO/RTO members.<br>R1.1 - Change the article to ". . . implemented, and made available to the RRO's, NERC, and stakeholders."<br>R1.4 - Combine this article into R1.3.<br>R4 - Delete as it is included in the revised R1.1. | |

*When completed, e-mail to: gerry.cauley@nerc.net*

# Standard Authorization Request Form

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| Title of Proposed Standard | Revision to Standards MOD 004, MOD005, MOD006, MOD 008, and MOD 009 |
| Request Date | revised February 15, 2006 |

| **SAR Requestor Information** | **SAR Type** (Put an 'x' in front of one of these selections) | |
|---|---|---|
| Name<br>ATCT SAR Drafting Team<br>atctdt_plus@nerc.com | ☐ | New Standard |
| Primary Contact Larry Middleton SAR Drafting Team Chair | X | Revision to existing Standard(s) |
| Telephone (317) 249-5447<br>Fax | ☐ | Withdrawal of existing Standard |
| E-mail lmiddleton@midwestiso.org | ☐ | Urgent Action |

**Purpose/Industry Need** (Provide one or two sentences)

The existing standards on TRM should be revised to require crisp and clear documentation of the calculation of TRM and make various components of the methodology mandatory so there is more consistency across methodologies.

The existing standards on CBM should be revised to require crisp and clear documentation of the calculation of CBM and make various components (zero values could be acceptable, if applicable) of the methodology mandatory so there is more consistency across methodologies. The Standard drafting team should identify and clarify the various definitions of CBM.

The SAR drafting team will not be addressing the measures, compliance, and regional differences. Those will be reserved for the Standard Drafting Team. The Standard Drafting Team should also consider whether the definitions of CBM and TRM should be revised.

The Standard Drafting Team should coordinate its work with the related proposal for the draft NAESB business practice R05004.

**Detailed Description** (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

Below is a list of issues/items that should be addressed in the revision to MOD-004, 5, 6, 8, and 9. The SAR drafting team does not believe any of the existing requirements should be eliminated during this revision; however, the SAR drafting team expects some existing requirements may be modified and/or re-organized during the revision.

In addition to the specific changes suggested in the SAR Appendix 1, the revisions to these standards should address these additional issues:

- Cataloging of various uses and interpretations of CBM
    - How should they be differentiated?
- Should CBM be an explicit reservation?
    - How and if it would be made a requirement
    - Would it be source to sink or partial path?
- How it might impact systems that use CBM for resource adequacy?
- Whether there should be a reciprocal agreement for the use of CBM.
- Should CBM be based on required or recommended planning reserve.
- Whether entities should plan and reinforce their systems for the amount of CBM being reserved.
- How would RRO (and NERC?) approve CBM/TRM methodologies
- How should TRM be made consistent with applicable planning criteria?

The SAR drafting team has included suggested changes related to these issues in Appendix 1 to this SAR. These are a result of discussions during the SAR drafting and are provided as information that may aide the standard drafting team during their work.

### *Reliability Functions*

| **The Standard will Apply to the Following Functions** *(Check box for each one that applies by double clicking the grey boxes.)* | | |
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| ☐x | Reliability Authority | Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority. |
| ☐x | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time |
| ☐x | Interchange Authority | Authorizes valid and balanced Interchange Schedules |
| ☐x | Planning Authority | Plans the bulk electric system |
| ☐x | Resource Planner | Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area. |
| ☐x | Transmission Planner | Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area. |
| ☐**x** | Transmission Service Provider | Provides transmission services to qualified market participants under applicable transmission service agreements |
| ☐x | Transmission Owner | Owns transmission facilities |
| ☐x | Transmission Operator | Operates and maintains the transmission facilities, and executes switching orders |
| ☐ | Distribution Provider | Provides and operates the "wires" between the transmission system and the customer |
| ☐x | Generator Owner | Owns and maintains generation unit(s) |
| ☐x | Generator Operator | Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services |
| ☐x | Purchasing-Selling Entity | The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required |
| ☐x | Market Operator | Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch. |
| ☐x | Load-Serving Entity | Secures energy and transmission (and related generation services) to serve the end user |

Applicability to be determined by standard drafting team.

### *Reliability and Market Interface Principles*

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| **Applicable Reliability Principles** *(Check boxes for all that apply by double clicking the grey boxes.)* | |
| x☐ | Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☐x | Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☐ | Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented. |
| ☐x | Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems. |
| ☐x | Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions. |
| ☐ | The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis. |

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| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)* |
| The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes |
| An Organization Standard shall not give any market participant an unfair competitive advantage.Yes |
| An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes |
| An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes |
| An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

### *Related Standards*

| Standard No. | Explanation |
|---|---|
| t.b.d | LTATF SAR for ATC/AFC and TTC (submitted with this SAR). |
| R05004 | NAESB proposed Business Practice for a single Business Practice Standard. |
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### *Related SARs*

| SAR ID | Explanation |
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| | Resource Adequacy SAR/Standard |
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### *Regional Differences*

| Region | Explanation |
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| ECAR | |
| ERCOT | |
| FRCC | |
| MRO | |
| NPCC | |
| RFC | |
| SERC | |
| SPP | |
| WECC | |

### *Related NERC Operating Policies or Planning Standards*

| ID | Explanation |
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**Appendix 1**

**proposed changes are highlighted in green**

**SUGGESTED REVISIONS to MOD-004-0**

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a CBM methodology that is approved by the RRO. A Transmission Service Provider that crosses multiple RRO boundaries shall get approval for its CBM methodology either from each of the respective RROs, or from NERC.

Each CBM methodology shall :

R1.1 Specify that the method used to determine generation reliability requirements as the basis for CBM shall be consistent with the respective generation planning criteria.

R1.2 Specify the frequency of calculation of the generation reliability requirement and associated CBM values.

- Require that the calculations must be verified at least annually.
- Require that the dates seasonal CBM values apply must be specified.

R1.3 Require that generation unit outages considered in a transmission provider's CBM calculation be restricted to those units within the transmission provider's system.

[The standard drafting team should discuss whether CBM should be an explicit reservation and how it would be made a requirement.]

R1.4 Require that CBM be preserved only on the transmission provider's system where the load serving entity's load is located (i.e., CBM is an import quantity only).

[The standard drafting team should discuss whether there could be a reciprocal agreement for the use of CBM.]

R1.5 Describe the inclusion or exclusion rationale in the CBM calculation for generation resources of each LSE including those generation resources not directly connected to the transmission provider's system but serving LSE loads connected to the transmission provider's system. The following rationale must be included in all methodologies:

R1.7.1 All generation directly connected to the transmission provider's system being used to serve load directly connected to that system will be considered in the CBM requirement determination.

R1.7.2 The availability of generation not directly connected to the transmission provider's system being used to serve load directly connected to that system would be considered available per the terms under which it was arranged.

R1.6 Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system. The following rationale must be included in all methodologies:

R1.7.1 The following units shall be included in the CBM requirement determination because they are considered to be the installed generation capacity, committed to serve load, directly connected to the transmission system for which the CBM requirement is being determined:

i. Generation directly connected to the transmission provider's system but not obligated to serve load directly connected to that system, will be incorporated into the CBM requirement determination as follows:

1. Generation directly connected to the transmission provider's system, but committed to serve load on another system, will not be included in the CBM requirement determination for the transmission system to which the generator is directly connected.)

2. Generation directly connected to the TSP's system, but not committed to serve load on any system, will be included in the CBM requirement determination for the transmission system to which the generator is directly connected as follows:

The TSP will use the best information available to them (i.e. confirmed or requested transmission service/no service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology.

R1.7 Describe the formal process and rationale for the RRO to grant any variances to individual transmission providers from the Regional CBM methodology.

R1.7.1 Require any variances must also be approved by NERC or its designate.

R1.8 Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.

R1.9 Describe the inclusion or exclusion rationale for the loads of each LSE, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).

R1.10 Describe any adjustments to CBM values to account for generation reserve sharing arrangements (i.e. Use of CBM and a reserve sharing event simultaneously occurring that is not planned for). Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

[The standard drafting team should consider paragraph below:]

R1.11 Require that CBM be based on the required or recommended planning reserve. In other words, a load serving entity that does not arrange for resources at least equal to the recommended or required planning reserve levels does not benefit by causing a higher CBM.

[The standard drafting team should consider the option below:]

R1.12 Require that the appropriate entities will plan and reinforce the transmission system for the amount of CBM being preserved.

R2. The RRO's most recent version of the documentation of each entity's CBM methodology shall be available on a web site accessible by NERC, the RROs, and the stakeholders in the electricity market.

M3. Each RRO, in conjunction with its members, shall develop and implement a procedure to review the CBM calculations and values of member transmission providers to ensure that they comply with the Regional CBM methodology and are periodically updated (at least annually) and available to stakeholders. Documentation of the results of the most current Regional reviews shall be provided to NERC or its designate within 30 days of completion.

- The RRO must review and approve the TSP methodology to ensure it is consistent with the RRO's Planning Criteria. The TSP is responsible for ensuring that CBM calculations are consistent with the individual TOs planning criteria.

-----------------------------------------------

**SUGGESTED REVISIONS to MOD-005-0**

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review (at least annually) the CBM calculations and the resulting values of member Transmission Service Providers. The CBM review procedure shall:

R1.1 Indicate the frequency is at least annual, under which the verification review shall be implemented.

R1.2 Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to stakeholders.

R1.3 Require review of the consistency of the transmission provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the same components that comprise CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process. The procedure must specify how the consistency would be verified.

R1.3.1 Require verification that the appropriate entities are planning and reinforcing the transmission system for the amount of CBM being preserved. The procedure must specify how the verification would be determined. Transmission service providers must also perform this verification and report on the findings as specified below.

R1.4 Require CBM values to be updated at least annually and available to the Regions, NERC, and stakeholders in the electricity markets.

R2. The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days).

R3. Documentation of the results of the most current implementation of the procedure shall be sent to NERC within 30 days of completion.

**SUGGESTED REVISIONS to MOD-008-0**

R1. Each RRO in conjunction with its members, shall jointly develop and document a TRM methodology. This methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. If a RRO's members TRM values are determined by a RTO or ISO, than a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a regional methodology.

Each TRM methodology shall:

R1.1 Specify the update frequency of TRM calculations.

- Require that calculations be verified at least annually if determined to be required
- Require that dates that seasonal TRM values apply must be specified

R1.2 Specify how TRM values are incorporated into ATC calculations.

R1.3 Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM:

R1.3.1 aggregate load forecast error (not included in determining generation reliability requirements).
R1.3.2 load distribution error.
R1.3.3 variations in facility loadings due to balancing of generation within a Balancing Authority Area.
R1.3.4 forecast uncertainty in transmission system topology.
R1.3.5 allowances for parallel path (loop flow) impacts.
R1.3.6 allowances for simultaneous path interactions.
R1.3.7 variations in generation dispatch
R1.3.8 short-term operator response (operating reserve actions not exceeding a 59-minute window).
R1.3.9 Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.
R1.3.10 Additional detail on how variations in generation dispatch are handled from intermittent generation sources such as wind and hydro, need to be provided.

R1.4 Describe the conditions, if any, under which TRM may be available to the market as Non-Firm Transmission Service.

R1.5 Describe the formal process for the granting of any variances to individual transmission service providers from the regional TRM methodology.

R1.5.1 Any variances must also be approved by NERC or its designate

R1.6 Describe the methodology and conditions thereof that are used to reflect if TRM is reduced for the operating horizon.

R1.7 Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

R1.8 Specify TRM methodologies and values must be consistent with the approved planning criteria.

R1.8.1 Require that the appropriate entities will plan and reinforce the transmission system for the amount of TRM being preserved. The methodology must specify how the verification of the consistency would be determined.

R1.8.2 Each TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are entity specific or that are considered in each respective methodology shall also be explained along with their use in determining TRM values.

**SUGGESTED REVISIONS to MOD-009-0**

R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region , in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and resulting values of member transmission providers to ensure that they comply with the regional TRM methodology and are updated at least annually and available to transmission users.

- The RRO must review and approve the transmission service provider(s)' methodology to ensure it is consistent with the RRO's Planning Criteria. The RRO is responsible for ensuring that TRM calculations are consistent with the individual TOs planning criteria.

The TRM review procedure shall:

R1.1 Indicate the frequency is at least annual, under which the verification review shall be implemented.

R1.2 Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to stakeholders.

R1.3 Require review of the consistency of the transmission service provider's or Transmission Owner's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process. The review process used by a transmission service provider or transmission owner also needs to be documented.

R1.3.1 Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

R1.4 TRM methodologies and values must be consistent with the applicable planning criteria

- The methodology must specify how the verification of the consistency would be determined

R2. The documentation of the regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC within 30 days of completion.

R3. Documentation of the results of the most current regional reviews shall be provided to NERC within 30 days of completion.

R4. Require TRM values to be verified at least annually and made available to the RROs, NERC, and stakeholders.

*When completed, e-mail to: mark.ladrow@nerc.net*

## Standard Authorization Request Form

| | |
|---|---|
| Title of Proposed Standard | Revision to Existing Standard MOD-001-0 |
| Request Date | Revised February 15, 2006 |

| **SAR Requestor Information** | | **SAR Type** (Put an 'x' in front of one of these selections) | |
|---|---|---|---|
| Name | ATCT SAR Drafting Team<br>atct_plus@nerc.com | ☐ | New Standard |
| Primary Contact | Larry Middleton<br>SAR Drafting Team Chair | x | Revision to existing Standard |
| Telephone<br>Fax | (317) 249-5447 | ☐ | Withdrawal of existing Standard |
| E-mail | lmiddleton@midwestiso.org | ☐ | Urgent Action |

**Purpose/Industry Need** (Provide one or two sentences)

This request changes existing modeling standard(s) by adding a requirement for transmission providers to coordinate the calculation of TTC/ATC/AFC and requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies.

Such changes will enhance the reliable use of the transmission system without needlessly limiting commercial activity. This request adds a requirement for documentation of the methodologies used to coordinate TTC/ATC/AFC*. In addition, a requirement is added for the enhanced documentation of the calculation methodology.

The Standards Authorization Request (SAR) drafting team did not address the measures, compliance, and regional differences. Those will be reserved for the standard drafting team.

*TTC – Total Transfer Capability

*ATC – Available Transfer Capability

*AFC – Available Flowgate Capability

*the drafting team may also deem it appropriate to define TFC – Total Flowgate Capability

***Reliability Functions***

| **The Standard will Apply to the Following Functions** *(Check box for each one that applies by double clicking the grey boxes.)* | | |
|---|---|---|
| ☐x | Reliability Authority | Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority. |
| ☐x | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time |
| ☐x | Interchange Authority | Authorizes valid and balanced Interchange Schedules |
| ☐x | Planning Authority | Plans the bulk electric system |
| ☐x | Resource Planner | Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area. |
| ☐x | Transmission Planner | Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area. |
| ☐x | Transmission Service Provider | Provides transmission services to qualified market participants under applicable transmission service agreements |
| ☐x | Transmission Owner | Owns transmission facilities |
| ☐x | Transmission Operator | Operates and maintains the transmission facilities, and executes switching orders |
| ☐ | Distribution Provider | Provides and operates the "wires" between the transmission system and the customer |
| ☐x | Generator Owner | Owns and maintains generation unit(s) |
| ☐x | Generator Operator | Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services |
| ☐x | Purchasing-Selling Entity | The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required |
| ☐x | Market Operator | Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch. |
| ☐x | Load-Serving Entity | Secures energy and transmission (and related generation services) to serve the end user |

***Reliability and Market Interface Principles***

| **Applicable Reliability Principles** *(Check boxes for all that apply by double clicking the grey boxes.)* | |
|---|---|
| ☐x | 1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☐x | 3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☐ | 4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented. |
| ☐ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems. |
| ☐x | 6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis. |

| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)* |
|---|
| 1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes |
| 2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes |
| 3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes |
| 4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes |
| 5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

**Detailed Description** (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

Definitions of Terms used in standard:

The standard drafting team should develop a definition for AFC (and TFC, if needed), and if necessary, revise the definitions for ATC and TTC. (some straw man definitions are contained in Appendix 2)

In those definitions, the standard drafting team should provide clarification (and differentiation) between the uses and application of the defined terms, particularly as the terms would be applied to either specific facilities or paths between two areas.

The standard drafting team should specify how criteria for determining flowgates would be used in an AFC/ATC process.

The standard drafting team should add a requirement for transmission providers to coordinate the calculation of TTC/ATC/AFC and require that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies.

The standard drafting team should add a requirement for the enhanced documentation of the TTC/ATC/AFC calculation methodology.

**NOTE: Many of the specific recommendations for changes to the standard(s) from the SAR drafting team have be moved to Appendix 1 so as to not bind the hands of the standard drafting team.**

**--------------------------------------------------------------------**

Below is a list of issues/items that should be addressed in the revision to MOD-001.

The SAR drafting team does not believe any of the existing requirements should be eliminated during this revision; however, the SAR DT expects some existing requirements may be modified and/or re-organized during the revision.

The revisions to this standard should:

- Finalize definitions for TTC (possibly add a definition for TFC), ATC and AFC
- Address the issue of methodology documentation and review of the methodology where an ISO/RTO may span multiple NERC regions
- Include a requirement that will enhance the required documentation of TTC and ATC calculations, increasing transparency of those calculations to the marketplace; also ensure it clearly defines who is responsible for that documentation.
- Require that the methodology document(s) are available to the industry
- Include a list of required data that must be coordinated for TTC and/or ATC/AFC calculations; such as, but not limited to: generation dispatch, transmission and generation outage, load forecasts, flowgate definitions/criteria.
- Consider trying to develop common criteria for establishing flowgates.
- Include a requirement that addresses issues surrounding the need to assign responsibility for analysis of third-party flowgates in TTC/ATC/AFC calculations to avoid double and triple evaluating of the same reservation request.

- Consider adding requirements to address that parties need to ensure 'agreement' between the coordinated ATC/AFCs values and require documentation of a process to define how discrepancies will be handled. For example, TSP1 should be denying service for a path that impacts a flowgate in TSP2 if the data received from TSP2 shows no service is available.
- Ensure requirements exist to document consistency between operational and planning TTC/ATC/AFC calculations.
- Consider changing the current approach of referencing TTC/ATC/AFC requirements as one group and separating them into TTC requirement(s) and AFC/ATC requirement(s)
- Consider adding more description on what is considered a 'standard' methodology (at what level of detail does the 'standard methodology' document need to go and can there be variations/options allowed within the methodology document?);
- Ensure that any mention of a standard methodology clearly refers to TTC or ATC or AFC.
- Consider requiring that the regional document describe what data is being coordinated between what TSPs and why that 'set' of TSPs are coordinating such data. Set a guideline/criteria associated with who must coordinate.
- Ensure that all requirements are stated in such a way that they can be quantified and measured
- Provide clarification of how the standard(s) would apply to the Western and Eastern (also ERCOT) Interconnections. (For example, WECC uses "committed uses or existing transmission committments".
- Establish a consistent set of definitions across the Western, Eastern, and ERCOT Interconnections, considering aspects of each.
- Establish a baseline set of equations for ATC and AFC and any appropriate component, which would include margins such as those specified in MOD 2, MOD 3, MOD 4, MOD 5, MOD 6, MOD 8, and MOD 9, that will incorporate the set of definitions referred to above, allowing for a zero value for a variable that is not used in a specific interconnection. E.g. : ATC = TTC – committed uses – CBM – TRM. (committed uses may be referred to as base flow or existing transmission commitments.)

This SAR lists items that the Long Term AFC/ATC Task Force (LTATF) and the SAR drafting team believe are required to be addressed in the standard revision. However, this list does not prevent the standard drafting team from proposing additional requirements to ensure the objectives of this standard revision are met.

The SAR drafting team has included suggested changes related to these issues as Appendix 1 to this SAR. These are a result of discussions during the SAR drafting and are provided as information that may aide the Standard drafting team during their work.

If during the development of changes to MOD-001, corresponding changes are required to MOD-002 and MOD-003 for consistency the Standard DT should propose such changes to those standards.

**A. Introduction**

1. **Title:** **Development and Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies**
2. **Number:** MOD-001-0

3. **Purpose:** The purpose of the standard is to promote the consistent and uniform application of Transfer Capability calculations among Transmission Service Providers. The standard will require methodologies to be developed and documented for calculating Total Transfer Capability (TTC), Available Transfer Capability (ATC), and Available Flowgate Capability (AFC) that comply with NERC definitions for TTC, ATC, and AFC; NERC Reliability Standards; and applicable Regional Reliability Organization criteria.

4. **Applicability:**

   **4.1.** Transmission Service Providers and Regional Reliability Organizations

   **4.2.** Others as may be deemed appropriate by the standard drafting team

5. **Effective Date:** **t.b.d.**

***Related Standards***

| Standard No. | Explanation |
|---|---|
| MOD-002-0 | Review of TTC and ATC Calculations and Results |
| | |
| FAC-005-0 | Electrical Facility Ratings for System Modeling |
| MOD 003-0 | Procedure for Input on TTC and ATC Methodologies and Values |

***Related SARs***

| SAR ID | Explanation |
|---|---|
| T.B.D | SAR for TRM and CBM (submitted with this SAR) |
| R05004 | NAESB proposed Business Practice for a single Business Practice Standard to be developed related to:<br>modifying NAESB Business Practice for Open Access Same-time Information Systems (OASIS) WEQ BPS-001-000, WEQSCP-001-000, and WEQDD-001-000 be modified or developing a new business practice standard(s) as required:<br><br>1) the processing of transmission service requests, which use TTC/ATC/AFC,in coordination with NERC changes to MOD 001,<br><br>2) 1) the processing of transmission service requests, which use CBM/TRM. |
| FAC-010-1 | Determine Facility Ratings, Operating Limits, and Transfer Capabilities |
| | |
| | |
| | |
| | |
| | |

***Regional Differences – to be determined by standard drafting team***

| Region | Explanation |
|---|---|
| ECAR | |
| ERCOT | |
| FRCC | |
| MRO | |

| | |
|---|---|
| NPCC | |
| RFC | |
| SERC | |
| SPP | |
| WECC | |

***Related NERC Operating Policies or Planning Standards***

| **ID** | **Explanation** |
|---|---|
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# Appendix 1

## B. Requirements

R1. All Transmission Service Providers within a RRO, shall jointly develop and document a TTC, ATC, and/or AFC methodology that is approved by the RRO.

A Transmission Service Provider that crosses multiple RRO boundaries shall get approval for its TTC, ATC, and/or AFC methodology either from each of the respective RROs, or from NERC.

This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

Each TTC and ATC/AFC methodology shall address each of the items listed below:

R1.1 Include a narrative explaining how TTC and ATC/AFC values are determined and used in evaluating transmission service requests. In addition, an explanation for all items listed here must also include any process that produces values that can override the TTC and ATC/AFC values.

R1.2 Account for how the reservations and schedules for Firm (non-recallable) and Non- firm (recallable) Transmission Service, both within and outside the Transmission Service Provider's system, are included. An explanation must be provided on how reservations that exceed the capability of the specified source point are accounted for. (i.e. how does the Transmission Service Provider's calculation account for multiple concurrent requests for transmission service in excess of a generator's capacity or in excess of a Load Serving Entity's load).

R1.3 Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations. Source and sink points are further defined in the Source and Sink Points white paper contained in Appendix B of the Final LTATF Report.

R1.4 Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)

R1.5 Require that TTC/ATC/AFC values and postings be reviewed at a minimum frequency and updated if changed to assure proper representation of the transmission system. These values will be made available to stakeholders at a similar frequency.

R1.6 Indicate the treatment and level of customer demands, including interruptible demands.

R1.7 Require that the data listed below, and other data needed by transmission providers for the calculation of TTC and ATC/AFC values are shared and used between Transmission Service Providers. Transmission Service Providers requiring data should request the data as needed. In addition, specify how this information is coordinated and used to determine TTC and ATC/AFC values. If some data is not used or coordinated, provide an explanation. The required minimum update frequency[1] for each item is listed below:

R1.7.1 **Generation Outage Schedules**: Minimum 13 month time frame includes all generators (for 20 MW or more) used in the ATC/AFC calculation). The update frequency is daily. The information exchanged shall differentiate between pending and approved outages.

R1.7.2 **Generation dispatch order**: Generic dispatch participation factors on a control area/market basis. The update frequency is as required.

R1.7.3 **Transmission Outage Schedules**: Minimum 13 month time frame, updated daily for all bulk electric system facilities that impact ATC/AFC calculations; updated once an hour for unscheduled outages. The information exchanged shall differentiate between pending and approved outages.

R1.7.4 **Interchange Schedules** : The update frequency is hourly.

R1.7.5 **Transmission Service Requests**: The update frequency is daily. This will include all requests, regardless of status, for all future time points.

R1.7.6 **Load Forecast**: supplied via the SDX (or similar method), includes hourly data or peak with profile for the next 7-day time frame. The update frequency is daily. In addition, daily peak for day 8 to 30 updated at least daily, and monthly for next 12 months updated at least monthly.

R1.7.7 **Flowgate AFC data exchange:** For transmission service providers in the Eastern Interconnection, firm and non-firm AFC values will be exchanged. The minimum update frequency is as follows: Hourly AFC once-per-hour, Daily AFC once-per-day and Monthly AFC once-per-week. [Note to standard drafting team. See Appendix A from LTATF Final Report section 2.1].

R1.7.8 **Flowgate rating**: Seasonal flowgate ratings will also be provided and exchanged. Users of the flowgate should have the same rating in their calculation as the owner of the facility. Updated as required. [The standard drafting team will need to clarify what

[1] The update frequency specified should allow for improvements in technology, communication, etc, that might better represent actual system conditions.

definitions are used. Would this be TFC, thermal or stability?] [The Standard Drafting team will need to define seasonal.]

R1.7.9 **Calculation model**: Updated models will be made available to neighboring/affected calculators. Changes/upgrades to facilities that would change the rating of the facilities that are limiting facilities should be included the models [joint modeling results can be utilized where applicable]

R1.7.10 **Criteria and definitions:** Flowgates and flowgate definitions/criteria should be exchanged with neighboring/affected calculators on a seasonal basis, or more often as required to represent actual system conditions.

R1.8 Describe how the assumptions for and the calculations of TTC and ATC/AFC values change over different time (such as hourly, daily, and monthly) horizons.

R1.9 Describe assumptions used for positive impacts and counterflow of transmission reservations, and /or schedules, including the basis for the assumptions.

R1.10 Describe assumptions used for generation dispatch for both external and internal systems for base case dispatch and transaction modeling, including the basis for the assumptions.

R1.11 Ensure that the TTC/ATC/AFC calculations are consistent with the Transmission Owner's/Transmission Planner's (leave Functional Model designation to Standard DT) planning criteria and operating criteria [The standard drafting team will need to be more specific regarding time frames].
Note: this regards, for example 1) TSR studies not being subjected to more stringent criteria than what is in the planning studies, and 2) negative ATC/AFC are shown over long periods of time on an operating basis, but planning studies show no anticipated remedies.

R1.12 Describe the formal process for the granting of any variances to individual transmission service providers from the TTC/ATC/AFC methodology. (Standard Drafting team will describe who is responsible.)

- Any variances must be approved by NERC or its designate

R2. The most recent version of the documentation of each TTC, ATC, and AFC methodology shall be available on a web site accessible by NERC, the Regions, and the stakeholders in the electricity market. [standard drafting team: NEED to add a description how this would apply in WECC for TTC.]

C. Measures.
(<u>standard drafting team to develop procedures for audit to ensure adherence to stated methodology – see Appendix 3</u>)

# Appendix 2

**<u>Strawman Definitions from LTATF:</u>**

Total Transfer Capability (TTC):

TTC and ATC are defined in standard 1E1
Existing Transmission Commitments (ETC)
ATC is expressed as:
ATC = TTC – Existing Transmission Commitments ) – CBM – TRM

Flowgate is the name given to the transmission element(s) and associated contingency(ies) if any, that may limit transfer capability.

Flowgate Criteria – to be determined by SDT

Available Flowgate Capability (AFC)
AFC is expressed as:
AFC = [to be finalized by SDT]

The relationship between ATC and AFC is as follows:

$ATC_{(\text{Path A-B})} = AFC_{(\text{Most Limiting Flowgate for Path A-B})} / \text{Distribution Factor}_{(\text{Path A-B on Limiting Flowgate})}$

Daily, Monthly, Yearly TTC
Daily, Monthly, Yearly ATC
Daily, Monthly, Yearly TRM
Daily, Monthly, Yearly CBM

# Appendix 3 LTATF Suggested Audit Methodology

M1. Each group of transmission service providers within a region, in conjunction with the members of that region, shall jointly develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC/AFC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC/AFC methodology, the NERC Planning Standards, and applicable Regional criteria.

M2. A review to verify that the ATC/TTC/AFC calculations are consistent with the TO's/TP's planning criteria is also required. The procedure used to verify the consistency must also be documented in the report. Documentation of the results of the most current reviews shall be provided to NERC within 30 Days of completion.

M3. Each entity responsible for the TTC and ATC/AFC methodology, in conjunction with its members and stakeholders, shall have and document a procedure on how stakeholders can input their concerns or questions regarding the TTC and ATC/AFC methodology and values of the transmission provider(s), and how these concerns or questions will be addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the stakeholders in the electricity market.

M4. The RRO must review and approve the ATC/TTC/AFC methodology to ensure it is consistent with the RRO's Planning and Operating Criteria.

The RRO is responsible for ensuring that TTC and ATC/AFC calculations are consistent with the individual TOs/TPs planning criteria.

Each procedure shall specify:

a) The name, telephone number, and email address of a contact person to whom concerns are to be addressed.

b) The amount of time it will take for a response.

c) The manner in which the response will be communicated (e.g., email, letter, telephone, etc.)

d) What recourse a customer has if the response is deemed unsatisfactory.

# CBM: Does it help or hinder reliability?

*This is **the minority opinion** of the ATCT Drafting Team. Although this paper may not apply to all Transmission Service Providers (TSPs), it does apply to several in the eastern interconnection.*

The design of the Capacity Benefit Margin (CBM) product as it is today does little to enhance reliability. In fact, one could deduce that the preservation of CBM actually hinders reliability. CBM is intended to be an instrument to ensure the availability of transmission during a local generation resource shortage, but until the industry can agree to coordinate these efforts, the result may be making things worse instead of better. In fact, current interpretations of the calculation and use of CBM by several TSPs cause several concerns:

1. **CBM is a partial path reservation without a designated generation source.**

   CBM is an import quantity only. There are no arrangements between TSPs for the reservation and use of CBM on neighboring transmission systems. This means that when CBM is being utilized on a TSP's system during emergency conditions, there still needs to be arrangements made with all external TSPs for the use of *their* transmission systems. There is absolutely no assurance that the transmission service will be available on that other TSP's system. Furthermore, since emergencies occur in real-time, firm service is not available due to timing requirements. In fact, the only service that is available is non-firm hourly service or non-firm secondary service. With TLR occurrences being the rule, rather than the exception, the risk of curtailment of the emergency import is very probable due to the use of non-firm transmission. There are currently no provisions in either the TLR procedure or any TSPs tariff that allow for special treatment for external Load Serving Entities (LSEs) to use their system for emergency (CBM) purposes. In addition to the transmission availability risk, there is also no assurance that generation resources will be available on the interfaces (or impact flowgates) on which CBM is reserved.

2. **Use of CBM can restrict adequate resource planning.**

   Another problem with the current CBM methodology employed by some TSPs is that a LSE that expects to have a capacity deficit is now less likely to be able to make a long-term capacity purchase to ensure resource adequacy. The shortage can almost be seen as a self-fulfilling prediction. The LSE may be forecasting a shortage based on a Loss of Load Expectation (LOLE) calculation, so CBM is added to the interface (or flowgates) to ensure deliverability during emergencies. Since CBM is on the interface (or flowgates), the LSE can not get firm transmission service to purchase capacity and is forced into an emergency situation. This seems to be an illogical approach and does not appear to be in the best interest of the LSEs who are trying to hedge against generation shortages and price risk.

The opposite problem can also occur. The LSE (or TSP) may calculate a CBM of 100 MW to maintain the correct LOLE and later the LSE can make a firm transmission and generation purchase (import) of 25 MW. The CBM should actually be decremented by 25 MW down to 75 MW. However, the CBM may not be calculated every time an LSE makes a firm capacity purchase. In this case, the CBM requirement would be 75 MW, but the TSP is reserving 100 MW. This would limit others from making firm economic purchases to hedge against price risk. Again, this is not in the best interest of the LSEs.

3. **LSEs that can choose which interfaces to reserve CBM could restrict competition in that area.**

   Some TSPs have affiliated LSEs and allow LSEs to determine which interfaces utilize CBM. A TSP's decision to set aside transmission capacity for emergency imports pursuant to either long-term reserve sharing arrangements or probabilistic LOLE calculations reduces the firm import capacity available to its competitors. Whether to reduce ATC/AFC for a CBM reservation, at which interface and in what amount, is a competitively significant decision that is driven by commercial choices which may be made by the large incumbent LSE. It reflects tradeoffs made by the LSE (and its generation/merchant function) as to reliance on internal vs. external generation for sources of energy and reserves. This procedure invites abuse.

4. **CBM should not be used as a substitute for "real" reserves.**

   There could be cases where LSEs are physically "short" real reserves, but use CBM to justify resource adequacy.

   Clearly, the current use of CBM has questionable reliability value. The lack of transparency, standardization, and auditable definition, coupled with the absence of procedures for CBM to be reserved and paid for like other transmission reservations, invites abuse. It also may provide a false sense of security that CBM will provide the transmission needed to import emergency generation.

**Proposed Solution**

The current use of CBM by some TSPs should be discontinued. Today, Capacity Benefit Margin (CBM) is defined as:

*The amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability* *requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.*

For some LSEs, the current use of CBM may be better than no CBM (although it may be harming some LSEs). Instead of setting aside CBM on a TSP's system as a reliability quantity without the appropriate charges, it would be more reasonable and reliable to require the LSE(s) to obtain a firm transmission path from source to sink and obtain contracts from outside generation to ensure resource adequacy.

Those entities that currently allow for the use of CBM to reduce generation reliability requirements would be better served by this approach than the CBM approach which "assumes" that uncommitted external resources will be there when you need them. This ensures that not only is transmission available in the event of an emergency, but generation will also be available because it is contracted for. It also assigns the cost of the transmission reservations and the cost of capacity to the LSE(s) who directly benefit. A CBM "assumption" about external capacity may be an unrealistic expectation in this time of shrinking capacity margins.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC Authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developmed as a standard on February 14, 2006.
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**Description of Current Draft:**

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| 1. Post revised standard for stakeholder comments. | February 15–March 16, 2007 |
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| 7. Post for recirculation. | TBD |
| 8. 30 Day posting before board adoption. | TBD |
| 9. Board adopts MOD-001-1. | TBD |
| 10. Effective date. | TBD |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Glossary of Terms Used in Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Available Flowgate Capability (AFC):** A measure of the capability remaining in the Flowgate for further commercial activity over and above already committed uses. It is equal to the Total Flowgate Capability less the impacts of Existing Transmission Commitments (including retail customer service), less the impacts of Capacity Benefit Margin and less the impacts of Transmission Reliability Margin.

**Existing Transmission Commitments (ETC):** Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

**Flowgate:** A single transmission element, group of transmission elements and any associated contingency (ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

**Network Response Method**: A method of calculating Transfer Capability for transmission networks where customer Demand, generation sources, and the Transmission systems are closely interconnected.

**Rated System Path Method:** A method of calculating transfer capability for transmission networks where the critical transmission paths between areas of the network have been identified and rated as to their achievable transfer loading capabilities for a range of system conditions.

**Total Flowgate Capability (TFC):** The amount of electric power that can flow across the Flowgate under specified system conditions without exceeding the capability of the Facilities. Typically expressed in the form of thermal capability. Flowgates can be proxies for Stability and other limiting criteria.

**Transmission Reservation:** A reservation is a confirmed Transmission Service Request.

**Transmission Service Request:** A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

## A. Introduction

1. **Title:** **ATC and AFC Calculation Methodologies**

2. **Number:** MOD-001-1

3. **Purpose:** To promote the consistent and uniform application and documentation of Available Transfer Capability (ATC), and Available Flowgate Capability (AFC) calculation methodologies for reliable system operations.

4. **Applicability:**

   **4.1.** Transmission Service Provider

5. **Proposed Effective Date:** TBD

## B. Requirements

**R1.** The Transmission Service Provider that calculates ATC (using either the Rated System Path Methodology or the Network Response Methodology) shall use the following equation to calculate ATC:

ATC = TTC – TRM – CBM – ETC

Where:

TTC = Total Transfer Capability

TRM = Transmission Reliability Margin

CBM = Capacity Benefit Margin

ETC = Existing Transmission Commitments

The requirements for calculating TTC, TRM, CBM and ETC will be developed in separate sets of standards.

**R2.** The Transmission Service Provider that calculates ATC shall recalculate ATC when any one of the following components of ATC changes:

**R2.1.** TTC

**R2.2.** TRM

**R2.3.** CBM

**R2.4.** ETC

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business Practices.

**R3.** The Transmission Service Provider that calculates ATC, shall, when requested, provide or make available, the following values (within 7 calendar days) to each Transmission Service Provider, Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator that requested the values and has a reliability-related need for the values:

**R3.1.** ATC

**R3.2.** TTC

**R3.3.** TRM

**R3.4.** CBM

**R3.5.** ETC

The requirements for calculating TTC, TRM, CBM and ETC will be developed in separate sets of standards.

**R4.** The Transmission Service Provider that calculates AFC (using a Network Response Methodology) shall use the following equation to calculate AFC:

AFC = TFC – (TRM * Distribution Factor) – (CBM * Distribution Factor) – the sum of (ETC impacts * respective Distribution Factors)

Where:

TFC = Total Flowgate Capability

TRM = Transmission Reserve Margin

CBM = Capacity Benefit Margin

ETC = Existing Transmission Commitments

The requirements for calculating TFC, TRM, CBM and ETC will be developed in separate sets of standards.

**R5.** The Transmission Service Provider that calculates AFC (using a Network Response Methodology) shall have a methodology that includes the following:

Please note that it may appear that the AFC methodology contains more requirements than that ATC methodology. Due to the characteristics of the ATC methodology, the corresponding level of detail will be contained in the standard that determines TTC (e.g. FAC 12 or FAC 13) when it is revised

**R5.1.** Separate consideration of the Transmission Reservation(s) for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside the Transmission Service Provider's system in the AFC calculation with respect to how each is treated in the Transmission Service Provider's counter flow rules.

**R5.2.** Separate consideration of the Schedules for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside the Transmission Service Provider's system in the AFC calculation with respect to how each is treated in the Transmission Service Provider's counter flow rules.

**R5.3.** Assumptions used for base case and transfer generation dispatch for both external and internal systems on OASIS (or its successor).

**R6.** The Transmission Service Provider that calculates AFC (using a Network Response Methodology) shall exchange the following data as agreed upon, or within 7 calendar days, with the Transmission Service Providers with whom AFC is coordinated and with each Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator that requested that data and has a reliability-related need for that data:

**R6.1.** Data describing coordinated transmission system elements scheduled to be taken out of or returned to service, that is updated and provided as changes occur.

**R6.2.** Data describing coordinated generation resources scheduled to be taken out of or returned to service, that is updated and provided as changes occur.

**R6.3.** A typical generation dispatch order that is updated at least prior to each peak load season or the generation participation factors of all units on an affected

Balancing Authority basis that is updated as required by changes in the status of the unit.

**R6.4.** The baseline power flow model for calculating AFC updated to reflect facility changes.

**R6.5.** Load Forecast information provided daily and updated as changes occur.

**R6.6.** Flowgates and Flowgate definitions and criteria provided on a seasonal basis, and when revised.

**R6.7.** Total Flowgate Capability (TFC) provided when initially established or revised, and provided daily thereafter.

**R6.8.** Firm and non-firm AFC values at the minimum update intervals listed below:

**R6.8.1.** Hourly AFC once per hour for 168 hours.

**R6.8.2.** Daily AFC once per day for thirty days.

**R6.8.3.** Weekly AFC once per day for four weeks.

**R6.8.4.** Monthly AFC once per month for 13 months.

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business Practices.

**R6.9.** Existing Transmission Commitments (ETC) information as reflected in an initial Power Flow model and provided within seven calendar days of the date the Power Flow Model is updated.

The requirements for calculating ETC may be developed in a separate standard following input from industry.

**R6.10.** Transmission Service Reservation information provided when revised once per hour.

**R7.** Each Transmission Service Provider that calculates AFC (using a Network Response Methodology) shall update its AFC values using the updated information received (from Transmission Service Providers with whom AFC is coordinated) at the frequency noted below:

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business

**R7.1.** For hourly, once per hour.

**R7.2.** For daily, once per day.

**R7.3.** For weekly, once per day.

**R7.4.** For monthly, once a week.

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business

**R8.** The Transmission Service Provider's methodology for calculating ATC or AFC shall identify how it accounts for the Transmission Reservations and Interchange Schedules for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside its Transmission Service Provider system.

**R9.** Each Transmission Service Provider shall consistently use its sole ATC or AFC calculation methodology for all instances of coordinating, calculating or posting ATC or AFC values.

**R10.** Each Transmission Service Provider shall post the most recent version of its ATC or AFC calculation methodology on its OASIS (or its successor).

NAESB will be asked to develop a template in their complementary business practice.

**R11.** Each Transmission Service Provider's ATC or AFC calculation methodology shall include or address the following:

**R11.1.** Identify the parties responsible for posting the ATC or AFC values on OASIS.

**R11.2.** Require that the calculation of ATC or AFC use the same criteria and assumptions used to conduct reliability assessments and internal expansion planning for different time frames (real-time; same day; day-ahead; and from day-ahead up to 13 months).

**R11.3.** Document the criteria used for calculating ATC or AFC values for the different time frames (real-time; same day; day-ahead; and from day-ahead up to 13 months) and the rationale for any differences between these.

**R11.4.** Identify the contingencies considered in the ATC and AFC calculations methodology.

**R11.5.** Require that the calculation of ATC or AFC for use in the 13 months and longer time frame use the same power flow models, and the same assumptions regarding load, generation dispatch, special protection systems, post contingency switching, and transmission and generation facility additions and retirements as those used in the expansion planning for the same time frame.

**R12.** Identify the Transmission Service Providers with which the data used in the calculation of ATC or AFC is exchanged.

**R13.** If the Transmission Service Provider approves a Transmission Service Request using a value other than and less than its value for ATC or AFC, then the Transmission Service Provider shall identify how it calculated the lesser value.

**R14.** The Transmission Service Provider shall require that the Transmission Customer provide both ultimate source and ultimate sink on the Transmission Service Request and shall require that the Transmission Customer use the same source and sink on Interchange Transaction Tags.

## C. Measures

## D. Compliance

## E. Regional Differences

**None**

## F. Associated Documents

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | April 1, 2005 | Effective Date | New |

| | | | |
|---|---|---|---|
| 0 | January 13, 2006 | Fixed numbering from R.5.1.1, R5.1.2., and R5.1.3 to R1.5.1., R1.5.2., and R1.5.3.<br>Changed “website” and “web site” to “Web site.” | Errata |

~~Introduction~~

~~Title: Documentation of Total Transfer Capability and Available Transfer Capability~~

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**Transmission Service Request:** A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

## A. Introduction

1. **Title:** **ATC and AFC Calculation Methodologies**

2. **Number:** MOD-001-~~0~~1

3. **Purpose:** To promote the consistent and uniform application ~~**of Transfer Capability calculations among transmission system users, the Regional Reliability Organization shall develop methodologies for calculating Total Transfer Capability (TTC) and**~~ and documentation of Available Transfer Capability (ATC~~**) that comply with NERC definitions for TTC and ATC, NERC Reliability Standards, and applicable Regional criteria.**~~), and Available Flowgate Capability (AFC) calculation methodologies for reliable system operations.

4. **Applicability:**

   ~~**4.1.** Regional Reliability Organization~~

   **4.1.** Transmission Service Provider

5. **Proposed Effective Date:** ~~**April 1, 2005**~~TBD

## B. Requirements

~~**R1.** Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. (Certain systems that are not required to post ATC values are exempt from this standard.) The Regional Reliability Organization's TTC and ATC methodology shall include each of the following nine items, and shall explain its use in determining TTC and ATC values:~~

~~**R1.1.** A narrative explaining how TTC and ATC values are determined.~~

~~**R1.2.** An accounting for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the Transmission Service Provider's system, are included.~~

~~**R1.3.** An accounting for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.~~

~~**R1.4.** A description of how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or because the reservations have not all been made.)~~

~~**R1.5.** A requirement that TTC and ATC values shall be determined and posted as follows:~~

~~**R1.5.1.** Daily values for current week at least once per day.~~

~~**R1.5.2.** Daily values for day 8 through the first month at least once per week.~~

~~**R1.5.3.** Monthly values for months 2 through 13 at least once per month.~~

~~**R1.6.** Indication of the treatment and level of customer demands, including interruptible demands.~~

~~**R1.7.** A specification of how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by Transmission Service Providers for the calculation of TTC and ATC values are shared and used within the Regional Reliability Organization and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regional Reliability Organizations. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation.~~

~~**R1.8.** A description of how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.~~

~~**R1.9.** A description of the Regional Reliability Organization's practice on the netting of transmission reservations for purposes of TTC and ATC determination.~~

~~**R2.** The Regional Reliability Organization shall make the most recent version of the documentation of its TTC and ATC methodology available on a Web site accessible by NERC, the Regional Reliability Organizations, and transmission users.~~

**R1.** The Transmission Service Provider that calculates ATC (using either the Rated System Path Methodology or the Network Response Methodology) shall use the following equation to calculate ATC:

ATC = TTC – TRM – CBM – ETC

Where:

TTC = Total Transfer Capability

TRM = Transmission Reliability Margin

CBM = Capacity Benefit Margin

ETC = Existing Transmission Commitments

The requirements for calculating TTC, TRM, CBM and ETC will be developed in separate sets of standards.

**R2.** The Transmission Service Provider that calculates ATC shall recalculate ATC when any one of the following components of ATC changes:

**R2.1.** TTC

**R2.2.** TRM

**R2.3.** CBM

**R2.4.** ETC

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business Practices.

**R3.** The Transmission Service Provider that calculates ATC, shall, when requested, provide or make available, the following values (within 7 calendar days) to each Transmission Service Provider, Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator that requested the values and has a reliability-related need for the values:

**R3.1.** ATC

**R3.2.** TTC

**R3.3.** TRM

**R3.4.** CBM

**R3.5.** ETC

The requirements for calculating TTC, TRM, CBM and ETC will be developed in separate sets of standards.

**R4.** The Transmission Service Provider that calculates AFC (using a Network Response Methodology) shall use the following equation to calculate AFC:

AFC = TFC – (TRM * Distribution Factor) – (CBM * Distribution Factor) – the sum of (ETC impacts * respective Distribution Factors)

Where:

TFC = Total Flowgate Capability

TRM = Transmission Reserve Margin

CBM = Capacity Benefit Margin

ETC = Existing Transmission Commitments

The requirements for calculating TFC, TRM, CBM and ETC will be developed in separate sets of standards.

**R5.** The Transmission Service Provider that calculates AFC (using a Network Response Methodology) shall have a methodology that includes the following:

**R5.1.** Separate consideration of the Transmission Reservation(s) for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside the Transmission Service Provider's system in the AFC calculation with respect to how each is treated in the Transmission Service Provider's counter flow rules.

**R5.2.** Separate consideration of the Schedules for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside the Transmission Service Provider's system in the AFC calculation with respect to how each is treated in the Transmission Service Provider's counter flow rules.

**R5.3.** Assumptions used for base case and transfer generation dispatch for both external and internal systems on OASIS (or its successor).

Please note that it may appear that the AFC methodology contains more requirements than that ATC methodology. Due to the characteristics of the ATC methodology, the corresponding level of detail will be contained in the standard that determines TTC (e.g. FAC 12 or FAC 13) when it is revised

**R6.** The Transmission Service Provider that calculates AFC (using a Network Response Methodology) shall exchange the following data as agreed upon, or within 7 calendar days, with the Transmission Service Providers with whom AFC is coordinated and with each Planning Coordinator, Transmission Planner, Reliability Coordinator, and Transmission Operator that requested that data and has a reliability-related need for that data:

**R6.1.** Data describing coordinated transmission system elements scheduled to be taken out of or returned to service, that is updated and provided as changes occur.

**R6.2.** Data describing coordinated generation resources scheduled to be taken out of or returned to service, that is updated and provided as changes occur.

**R6.3.** A typical generation dispatch order that is updated at least prior to each peak load season or the generation participation factors of all units on an affected Balancing Authority basis that is updated as required by changes in the status of the unit.

**R6.4.** The baseline power flow model for calculating AFC updated to reflect facility changes.

**R6.5.** Load Forecast information provided daily and updated as changes occur.

**R6.6.** Flowgates and Flowgate definitions and criteria provided on a seasonal basis, and when revised.

**R6.7.** Total Flowgate Capability (TFC) provided when initially established or revised, and provided daily thereafter.

**R6.8.** Firm and non-firm AFC values at the minimum update intervals listed below:

**R6.8.1.** Hourly AFC once per hour for 168 hours.

**R6.8.2.** Daily AFC once per day for thirty days.

**R6.8.3.** Weekly AFC once per day for four weeks.

**R6.8.4.** Monthly AFC once per month for 13 months.

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business Practices.

**R6.9.** Existing Transmission Commitments (ETC) information as reflected in an initial Power Flow model and provided within seven calendar days of the date the Power Flow Model is updated.

The requirements for calculating ETC may be developed in a separate standard following input from industry.

**R6.10.** Transmission Service Reservation information provided when revised once per hour.

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business

**R7.** Each Transmission Service Provider that calculates AFC (using a Network Response Methodology) shall update its AFC values using the updated information received (from Transmission Service Providers with whom AFC is coordinated) at the frequency noted below:

The timing requirements for reposting on OASIS will be in accordance with the complementary NAESB Business

**R7.1.** For hourly, once per hour.

**R7.2.** For daily, once per day.

**R7.3.** For weekly, once per day.

**R7.4.** For monthly, once a week.

**R8.** The Transmission Service Provider's methodology for calculating ATC or AFC shall identify how it accounts for the Transmission Reservations and Interchange Schedules for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside its Transmission Service Provider system.

**R9.** Each Transmission Service Provider shall consistently use its sole ATC or AFC calculation methodology for all instances of coordinating, calculating or posting ATC or AFC values.

**R10.** Each Transmission Service Provider shall post the most recent version of its ATC or AFC calculation methodology on its OASIS (or its successor).

NAESB will be asked to develop a template in their complementary business practice.

**R11.** Each Transmission Service Provider's ATC or AFC calculation methodology shall include or address the following:

**R11.1.** Identify the parties responsible for posting the ATC or AFC values on OASIS.

**R11.2.** Require that the calculation of ATC or AFC use the same criteria and assumptions used to conduct reliability assessments and internal expansion planning for different time frames (real-time; same day; day-ahead; and from day-ahead up to 13 months).

**R11.3.** Document the criteria used for calculating ATC or AFC values for the different time frames (real-time; same day; day-ahead; and from day-ahead up to 13 months) and the rationale for any differences between these.

**R11.4.** Identify the contingencies considered in the ATC and AFC calculations methodology.

**R11.5.** Require that the calculation of ATC or AFC for use in the 13 months and longer time frame use the same power flow models, and the same assumptions regarding load, generation dispatch, special protection systems, post contingency switching, and transmission and generation facility additions and retirements as those used in the expansion planning for the same time frame.

**R12.** Identify the Transmission Service Providers with which the data used in the calculation of ATC or AFC is exchanged.

**R13.** If the Transmission Service Provider approves a Transmission Service Request using a value other than and less than its value for ATC or AFC, then the Transmission Service Provider shall identify how it calculated the lesser value.

**R14.** The Transmission Service Provider shall require that the Transmission Customer provide both ultimate source and ultimate sink on the Transmission Service Request and shall require that the Transmission Customer use the same source and sink on Interchange Transaction Tags.

## C. Measures

~~**M1.** The Regional Reliability Organization shall provide evidence that its most recent TTC and ATC methodology documentation meets Reliability Standard MOD-001-0_R1.~~

~~**M2.** The Regional Reliability Organization shall provide evidence that its TTC and ATC methodology is available on a Web site accessible by NERC, the Regional Reliability Organizations, and transmission users.~~

## D. Compliance

~~**1. Compliance Monitoring Process**~~

~~**1.1. Compliance Monitoring Responsibility**~~

~~Compliance Monitor: NERC.~~

~~**1.2. Compliance Monitoring Period and Reset Time Frame**~~

~~Available on a Web site accessible by NERC, the Regional Reliability Organizations, and transmission users.~~

~~**1.3. Data Retention**~~

~~None identified.~~

~~**1.4. Additional Compliance Information**~~

~~None.~~

~~**2. Levels of Non-Compliance**~~

~~**2.1. Level 1:** The Regional Reliability Organization's documented TTC and ATC methodology does not address one or two of the nine items required for documentation under Reliability Standard MOD-001-0_R1.~~

~~**2.2. Level 2:** Not applicable.~~

~~**2.3. Level 3:** Not applicable.~~

~~**2.4. Level 4:** The Regional Reliability Organization's documented TTC and ATC methodology does not address three or more of the nine items required for documentation under Reliability Standard MOD-001-0_R1 or the Regional Reliability Organization does not have a documented TTC and ATC methodology available on a Web site in accordance with Reliability Standard MOD-001-0_R2.~~

## E. Regional Differences

**None ~~identified.~~**

## F. Associated Documents

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | April 1, 2005 | Effective Date | New |
| 0 | January 13, 2006 | Fixed numbering from R.5.1.1, R5.1.2., and R5.1.3 to R1.5.1., R1.5.2., and R1.5.3.<br>Changed “website” and “web site” to “Web site.” | Errata |
| | | | |
| | | | |

**Maureen E. Long**
Standards Process Manager

February 15, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

## Announcement: Three 30-day Comment Periods Open

**The Standards Committee (SC) announces the following standards actions:**

### SAR to Amend the Assess Transmission Future Needs and Develop Transmission Plans SAR Posted for 30-day Comment Period February 15–March 16, 2007

The SAR to amend the already-approved SAR for Assess Transmission Future Needs and Develop Transmission Plans (Project 2006-02) proposes to add TPL-005-0 and TPL-006-0 to the list of transmission planning standards currently addressed (TPL-001 through TPL-004), to consider issues raised by FERC and stakeholders regarding this set of standards, and to bring the entire set of standards into conformance with the ERO Rules of Procedure and the latest version of the Reliability Standards Development Procedure. Please use the comment form to provide comments on this SAR amendment.

### First Standard (MOD-001-1) in the Series of ATC/TTC/AFC Revisions Posted for 30-day Comment Period February 15–March 16, 2007

The first standard modified under Project 2006-07, MOD-001-1 — ATC and AFC Calculation Methodologies, requires the Transmission Service Provider to document and use a single methodology for calculating ATC or AFC. The drafting team is soliciting comments on the proposed requirements before developing the measures and compliance elements. Please use the comment form to provide comments on this draft standard's proposed requirements.

### Second Draft of SAR for Backup Facilities Posted for 30-day Comment Period February 15–March 16, 2007

The SAR for Project 2006-04 proposes modifying EOP-008-0 — Plans for Loss of Control Center Functionality. The revisions to EOP-008 focus on ensuring the continuation of functionality needed for reliable system operation regardless of the manner in which it is achieved. The modifications will consider issues raised by FERC and stakeholders about this standard, and will bring the standard into conformance with the ERO Rules of Procedure and the latest version of the Reliability Standards Development Procedure. Please use the comment form to provide comments on this SAR.

### Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

| |
|---|
| **Group Comments (Complete this page if comments are from a group.)** |
| **Group Name:** |
| **Lead Contact:** |
| **Contact Organization:** |
| **Contact Segment:** |
| **Contact Telephone:** |
| **Contact E-mail:** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☐ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☐ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

   ☐ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments:

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☐ No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☐ No

    Comments:

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☐ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☐ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments:

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments:

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments:

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

Comments:

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
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| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
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| ☒ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:** APPA

**Lead Contact:** **E. Nick Henery**

**Contact Organization:** **APPA**

**Contact Segment:** **1**

**Contact Telephone:** **202-467-2985**

**Contact E-mail:** **nhenery@APPAnet.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| L. Earl Fair | Gainesville Regional Utilities | FRCC | 1 |
| Matt Schull | ElectriCities of North Carolina | SERC | 1 |
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## Background Information

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A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: The definition is too vague to be used as a major component of the ATC Calculations. Therefore a Standard needs to be developed to determine the rules for what is ETC, where to post ETC, and the requirements for archiving the ETC for future Compliance Records and Auditing.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments: A Transmission Service Request is a request to reserve Transmission Capacity. If accepted and confirmed, it is not necessary for the Transmission Customer to move energy on this Transmission Capacity. In fact, it may be used for operating reserves and energy would only be scheduled on this capacity if there was an emergency. The definition should read in a manner that the Transmission Customer is requesting Transmission Capacity from a point of receipt and points of delivery.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

☐ Already approved definition

Comments: Flowgate are also used in the Western Interconnection where there is not an IDC.

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

    **Operating Horizon** — Time frames encompassing same-day and real-time periods.

    **Scheduling Horizon** — Time frames encompassing the day-ahead period.

    **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

    **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

    Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

    ☐ N/A — these terms do not need to be defined for use in this standard

    ☐ The terms do need to be defined and I do agree with the proposed definitions

    ☒ The terms do need to be defined but I don't agree with the proposed definitions

    Comments: This Standard does not need to redefine what the planners and operators of the BES has already defined. The Regions, Reliability Coordinator, Planners and Transmission Operators have established what is the Planning Horizons (T >= 1 Year) and Operating Horizon (T< 1 Year).

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

    ☐ Agree

    ☒ Disagree

    Comments: This Standard Drafting Team should not try to define terms that have been used by planners, operators, and Reliability Coordinators for many years. The terms Rated System Path (RSP) Method and Network Response (NR) Method have already been defined or described in many white papers for operators and planners. Why is the following an incorrect statement; "The method (RSP, NR, or Flowgate) will be determined by the method that the planners and operators use for that part of the Bulk Electric System."

**Comment [m1]:** While these terms may have been used by entities for many years, one of the purposes of the standard is to promote consistency. Defining these terms in a standard is a step in that direction. I would agree with the definitions of terms.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

    ☐ Yes

    ☒ No

Comments: As written the Standard is unclear and could not be audited for compliance. Numerous requirements have been omitted or written so incomplete that it is uncertain what a Transmission Service Provider is to do to provide a accurate ATC/AFC that is consistent with other TSPs. Requirements listed in MOD-001, particularly for flowgate, are the responsibility of the planners and operators for determining transfer capability. Many of the requirements, particularly for Flowgate are rules for determining ETC, not posting ATC values.

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments: A Transmission Service Provider (TSP) function will only sell excess transmission capacity and not determine what methodology that is used to plan and operate the BES. How would a TSP come up with a different method when it is the planners and operators that determine a method? Requirements 1 and 4 do not address the formula for determining non-firm ATC; does not address if TSP is Monthly, Daily, or Hourly in Requirement 1; and does not address how many values of Monthly Daily, and Hourly ATC should be posted. In addition, Requirement 4 does not address how the TSP will determine an ATC from the AFC calculations? How will these be handled?

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

Comments: This will depend on if you are talking about Monthly, Daily, or Hourly ATC. If you are talking about Hourly ATC the change will need to be made quickly, However, if the ETC for Monthly changes the need to repost is not so important since the need for the Transmission capacity is much further into the future.

**Comment [m2]:** I would hope that most of these calculations are automated, and a change in any component would prompt an immediate recalculation and posting of ATC regardless of time period.

9. Do you agree with the frequency of exchanging data as specified in Requirement 6?

☒ Yes

☐ No

Comments: The need to exchange data will depend upon which component is changing. If the TTC or TFC is changing in the operating time horizon the Reliability Coordinator will need to exchange this information quickly to several Reliability Functions including Transmission Service Providers. Again in the operating time horizons if the ETC, CBM, or TRM changes the Transmission Service Providers need to recalculate ATC and post this new information quickly to keep the Transmission Customers updated in the quick moving operating horizon.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

☐ Yes

☒ No

Comments: This Standard is written to make the industry believe that only one ATC will be calculated for each Transmission Service Provider. In reality, the TSP will post several ATCs; one ATC for each path or network the TSP is marketing transmission capacity. Each individual path or network will only use one method, but a TSP's planners may use different methods to plan and operate different paths in their system. MISO and PJM are entities that use two methods to market transmission capacity in its system. They only uses AFC at the borders or seams of their system to determine how much transmission capacity is available at their seams, while they use LMP to determine how much transmission capacity is available on their interior system. BPA will use flowgates to determine how much ATC is available to its Transmission Customer on the interior of their system, while BPA uses Transfer Path on its seams to determine how much transmission capacity is available to Transmission Customers exterior to their system.

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

☒ No

Comments: It is not necessary in this Standard. It will be necessary to explain difference in one of the Standards that spell out the rules for TTC, ETC, CBM or TRM. This is part of the posted assumptions that is necessary for the Transmission Service Provider to post when showing the values of the components that was used to calculate the number for ATC. MOD-001 is only for the rule of calculating ATC, i.e. maximum time between calculations and rules for recalculations; and posting ATC values and posting values and assumptions for the components. Rules for the components are in other standards.

**Comment [m3]:** R13 is addressing the case where a TSR is refused because the TSP is using an ATC or AFC value that is less than the calculated and/or posted value for some reason. I don't believe it is referring to the components of ATC or AFC. I think R13 is necessary.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments: Many of the requirements listed in MOD-001 are requirements needed in the Standards that set the rules for TTC, TFC, CBM, TRM, and ETC. The characteristic of each component will be made available to the industry if the Standards for the components are written properly. If MOD-001 is written in a manner that requires those characteristic to be provided to the TSP and require the TSP the post characteristics the SDT will meet its obligations.

R14 should be eliminated. Requiring the same ultimate source and ultimate sink on the Transmission Service Request and the Interchange Transaction Tag will harm commercial use of transmission service. It will force transmission users to redirect transmission service on OASIS every time a source or sink changes, even within the same control areas, while providing little, if any, benefit for reliability. If the drafting team feels this requirement is still needed, it should be passed to NAESB for inclusion as a business practice.

13. 13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

☐ Yes

☒ No

Comments: MOD-001 should only deal with ATC? and AFC and not the components. The rules for consistent and accurate methods of determining the individual components will be very complicated and numerous. Attempting to place all of these rules for the components in MOD-001 will make MOD-001 very large and impossible to measure and monitor the requirements.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

☒ Yes — TTC and TC are the same

☐ No — TTC and TC are not the same

Comments: TTC and TC are the same value determined by the planners or operation personnel for planning and operating horizons, respectively. It is recommended eliminating one of the terms to avoid confusion.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

☐ Yes

☒ No

Comments: A Flowgate is another tool to plan and operate ~~to~~ the BES. The Flowgate development and assumptions will be developed by the planners or operation personnel depending on the time horizon. The flowgate rating is determined as part of the FAC package for system rating, SOL determinations, and TTC (TC) determinations.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

Comments: In determining ATC for the different time horizons the CBM must match the same time horizon. The definition of ***Capacity Benefit Margin (CBM)*** *is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.* The primary responsibility of the CBM for the Hourly ATC will be the LSE to meet its responsibility of providing all energy and capacity for load, including operating reserves for the upcoming hours. The Monthly and Daily ATC values are long and short term planning issues where the planners project how much transmission capacity will be needed to ensure access to generation from interconnected systems to meet generation reliability requirements.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: In determining ATC for the different time horizons the TRM must match the same time horizon. The planners that plan at the different time horizons would be the best. The SDT has come up with a proposal of using a percentage of one of the system values that has been determined by the planners. This would be a very good ~~comprise~~ compromise and promotes a level of consistent calculations.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: NO.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: MOD-001 needs to address how the AFC calculations should be converted to the ATC calculations. MOD-001 needs to show that the ATC formulas for Monthly, Daily, and Hourly calculations are for different paths or networks. MOD-001 needs to show the formula to determine $ATC_{nonfirm}$ for Monthly, Weekly, and Daily calculations. The "future development plan must be modified to include the introduction and assistance of the NERC Compliance Staff to assist the team in developing Measurements, VRFs, and suggested terms of the compliance sections of the Standard.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information** **(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: John Bussman | | |
| Organization: AECI | | |
| Telephone: 4178859216 | | |
| E-mail: jbussman@aeci.org | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☒ | 5 — Electric Generators |
| ☒ **SERC** | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for ‘Existing Transmission Commitments (ETCs)’ — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☒ Yes

   ☐ No

   Comments:

2. This is the proposed definition for ‘Transmission Service Request’ — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☒ No

   Comments:

3. This is the proposed definition for ‘Flowgate’ — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☒ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☒ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☒ Yes

   ☐ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments:

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☒ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☒ Yes

    ☐ No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☒ Yes

    ☐ No

    Comments:

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☒ No

    Comments: TFC is well defined in the definitiond of terms in the standard section

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: Operating Horizon - hourly and daily
    Planning Horizon - weekly and monthly

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: Operating Horizon - hourly and daily

    Planning Horizon - weekly and monthly

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Comments: No

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: The standard does not provide a clear distiction for use of ATC verses AFC. It is our understanding that Requirements R1-R3 do not apply if the AFC methodology is used. For R4 to R6 if the AFC methodology is used then the TSP is not required to post ATC values, however AFC values would be posted.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☒ Yes

   ☐ No

   Comments:

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☒ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☒ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: To avoid confusion and future problems, the terms definitions should be consistent with Order 890. In which case, Operations and Long-Term Planning Horizons would not be broken out, rather would simply be "Planning Horizon."

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☒ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: The Transmission Service Provider should have no more than an hour to perform its recalculation of ATC. In the west, the clock should only start after it is determined that the TTC needs changing.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☐ No

   Comments: Not applicable

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☒ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☐ No

    Comments: Requirement 13 needs clarification, not sure if agree or dissagree.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☒ No

    Comments: The requirements in R11.2, R11.3, R11.4, R11.5 and R12 do not apply to entities that use the Rated System Path method and should not apply to their ATC calculations. For those that use the Rated System Path method these requirments should apply to the TTC calculations.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments: There should be standardization of the components used in the calculation of ATC and AFC. These standards do not have to be in this standard, however if there are new standards for these components and the new standards should take into account this standard.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments:

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: The Load Serving Entity should make the CBM calculations for all the time horizons (monthly, daily, weekly and hourly) listed above.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: TheTransmission Service Provider should make the TRM calculations for all the time horizons (monthly, daily, weekly and hourly) listed above.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: None

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: None

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information** | | |
|---|---|---|
| **(Complete this page for comments from one organization or individual.)** | | |
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| Organization: Bonneville Power Administration | | |
| Telephone: (360) 619-6254 / (360) 619-6421 | | |
| E-mail: fsknudsen@bpa.gov / ajnulph@bpa.gov | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

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| **Group Comments (Complete this page if comments are from a group.)** |
| **Group Name:** |
| **Lead Contact:** |
| **Contact Organization:** |
| **Contact Segment:** |
| **Contact Telephone:** |
| **Contact E-mail:** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: This definition merely describes a universe of explicit contractual or planning commitments that can be included in the calculation of ETC. To actually calculate ETC, however, these commitments must be translated into a representation of power transfers, i.e., the use of transfer capability. BPA does not agree that ETC should be addressed as a subcomponent of MOD-001-1 as suggested in P243 or Order 890; rather, it should be addressed in its own standard.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments: The definition as written implies that the request is for the physical movement of power from a specific generator to a requested point of delivery. In fact, the underlying nature of the service requested is to inject power into the grid at at a point of receipt, and to withdraw a like amount of power at a specific point on the grid for the benefit of an identified load.

   It is also not clear that a request for Network Integration Transmission Service would fall within this definition, because it may involve multiple PORs and PODs.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

☒ Proposed definition

☐ Already approved definition

Comments: Although the proposed definition is superior to the existing NERC definition, BPA believes that it may be too expansive. Specifically, the proposed definition does not clarify what is contemplated by the term "any associated contingencies". If the proposed standards are intended to ensure specificity and transparency of the contingencies, margins and/or uncertainties that may be considered when determining ATC, then BPA thinks any contingencies should be explicitly identified and quantified in the determination of TTC/TFC, TRM and/or CBM, and not in the definition of a flowgate. Also, it is not clear why a definition for transfer distribution factors is included in the definition of a flowgate. It would seem more appropriate to provide a separate stand-alone definition of transfer distribution factors.

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☒ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments: The definition of Network Response Method does not convey any substantive characteristics that describe what it is, or how to distinguish the method from the Rated System Path Method. The definition for Rated System Path likewise is insufficiently described and appears to merely describe a method that relies on a calculation of TTC for one or more paths. Since both methods appear to be based on the same formula (ATC/AFC = TTC/TFC-ETC-TRM-CBM), it is unclear what the substantive distinction is between the two methods.

   The Long-Term AFC/ATC Task Force April 14, 2005 report did not suggest that there were two fundamentally different methodological approaches to determining ATC. BPA recommends that the NERC ATC drafting team defer any efforts to refine the definitions of Rated System Path Method and Network Response Method until the standard requirements for calculating TFC, TRM, CBM and ETC are developed.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

   ☒ No

   Comments: See response to question 5.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: The transmission service provider should recalculate ATC comtemporaneously with any formal changes in TTC, TRM or CBM. The transmission provider should recalculate ATC immediately upon any event that changes ETC in the Operating Horizon and scheduling horizon. The transmission provider should recalculate ATC within two business days of any changes in ETC that affect the Operations Planning Horizon or beyond.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☒ No

   Comments: Requirement 6 appears to only apply to a transmission service provider that calculates AFC. BPA declines comment on this provision until such time as the distinction between the various methods becomes more clear. (see response to question #5.)

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☒ No

Comments: The substantive differences between the three aforementioned methods are not yet clear. However, if multiple methods are determined to be valid and acceptable approaches to calculating ATC/AFC, then the transmission provider should be able to employ multiple methods for calculating ATC/AFC on different parts of the transmission system, provided the various methods are applied consistently and are transparent.

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

☒ No

Comments: BPA does not understand requirement 13 as written. A transmission provider would normally approve a transmission request if transfer capability required by the request is LESS than the value of ATC available. If the transmission provider approves a request using a value for ATC lower than posted ATC, then the transmission provider should not have to identify or explain its actions. On the other hand, it would make sense to require an explanation if a transmission provider approves a transmission request using a value for ATC that is HIGHER than the value of ATC that is posted.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments: See BPA's response to question 19.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments: As written, the proposed standard does not achieve standardization, due in part to the uncertainties and lack of clarity in the variables within the ATC/AFC calculation. However, BPA supports development of individual standards for each variable within the ATC/AFC calculation.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☐ Yes — TTC and TC are the same

    ☒ No — TTC and TC are not the same

    Comments: Uncertain. FAC-012 speaks to reliability margins that may be applied when calculating transfer capabilities. This may give rise to inconsistencies between TC which incorporates margins, and ATC standards which, as currently drafted, imply that TRM is calculated separately from TTC.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☒ No

    Comments: TFC is similar to TC and should be addressed similarly to TC by revising the existing Facility Rating FAC-012-1.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: BPA does not employ CBM and declines to comment.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

Comments: The issue of time horizons should be determined through development of the TRM standard. The Transmission Service Provider should be reponsible for determining TRM.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: No.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

    R4. The formula in R4 describing AFC calculations is not accurate in the way it describes the application of distribution factors. Distribution factors are not necessarily applied to all of the components of the AFC calculation. Distribution factors are applied to transactions to allocate the percentage of the transaction that will flow on each applicable flowgate.

    R14. The requirement to provide the ultimate source and sink on the Transmission Service request, especially when the source or sink is on the other side of an interchange point, is not necessarily required for a Transmission Service Provider to determine the ATC/AFC impacts of a request. Additionally, this requirement may create difficulties for Transmission Customers since the ultimate source and sink may not be known at the time of the request submittal.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

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| **Group Comments (Complete this page if comments are from a group.)** |
| **Group Name:** |
| **Lead Contact:** |
| **Contact Organization:** |
| **Contact Segment:** |
| **Contact Telephone:** |
| **Contact E-mail:** |

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

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If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
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Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   X Yes

   ☐ No

   Comments:

   We agree with most of the components except "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion. Also, we question the need to specify "exchanges" and "deliveries" given that purchases and sales are already included.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   XYes

   No

   Comments: Definition is already sufficient and should not be expanded or changed.

   The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "and/or A/S" after the word "energy". The SDT should also review the definition of transmission service for consistency.

   The definition should include reference to ultimate Source and Sink. Add to end of proposed definition "… and from ultimate Source to ultimate Sink."

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Which definition do you prefer?

X Proposed definition

☐ Already approved definition

Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   X N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   We do not agree but if there is a need to reference time periods in the requirements, they should be specified in the requirements themselves and not as universal terms due to the lack of specificity in these.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   X Agree

   ☐ Disagree

   Comments: Remaining definitions: AFC, Network Response Method, Rated System Path Method, TFC, Transmission Reservation are OK.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   X Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team

consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

X No

Comments: We think those are the common used methodologies, we don't know of any others that are widely used.

However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.

Hence, we question the need for the qualifying statement – "using a Network Response Methodology" in parentheses, after "calculates AFC" in each of R4, R5 and R6.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

Comments: We think one day is reasonable in case of TTC, TRM or CBM changes.

If ETC changes, then re-calculation should be done within 1 or 2 hours.

9. Do you agree with the frequency of exchanging data as specified Requirement 6?

X Yes

☐ No

Comments: While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (ie. Before changes, after a change, after seven days from an agreement) is confusing. Is "as agreed upon" acceptable if it is greater than every seven days?

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

X Yes

☐ No

Comments: We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology as long as any methodology used is used consistently with transparency.

E.g. - CAISO currently uses one method on its ties (rated path)to other TSPs and one method for internal (network response). Additionally, for ties if adjacent TSPs use differing methodologies, the rating would not agree, so are we looking at a situation where one methodology may have to be used for each interconnection?

The CAISO agrees with the WECC MIC MIS ATC Task Force that this requirement should be eliminated or the word sole removed.

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

X No

Comments: Approving a request with insufficient AFC might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting a Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is insufficient. This is a common practice and should not have to be documented (justified) after the fact.

It might happen also if a re-dispatch agreement is accepted by a TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by the TP.

Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue should be addressed in the Business Practice.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

X Yes

X No

Comments:

R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study→refused).

R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is the intension then we agree.

R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations? TP's typically exchange Net Interchange based on Schedules and sometimes reservations. However that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of

ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.

R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.

R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. The Receiving Entity could update the AFC data on an hourly basis. If the Sending Entity doesn't update the data on an hourly basis, it is not effective.

R11.2 The term "same criteria" is too general, it should be more specific.

R11.4 The term "Identify contingencies" is too general. It is unclear whether this refer to outages or the contingency elements of flow gates.

R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology

Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:

- "Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC"

Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.

R14 Over stringent, particularly if AFCs are not calculated to the level or scope of granularity.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    X Yes

    ☐ No

    Comments: NERC should develop some general criteria: What should be included in the TTC, TFC, ETC, TRM, CBM? How should they be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation?

    Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    X Yes — TTC and TC are the same

    X No — TTC and TC are not the same

    Comments: This question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to an operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4 of the Comment Form. We believe TTC should be added into the FAC requirements as a defined term.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    X No

    Comments:

    TTC and TFC are reliability parameters that are determined by the transfer capability methodologies stipulated in FAC-012. These values are not determined by the TSP but by the RC or TOP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments:

    The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments:

    The question is inappropriate, because the standard does not attempt to define the methodology for TRM.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: To provide clarity and uniform application in the calculation of AFC and ATC the CAISO offers the following: When calculating AFC in the forward markets, this calculation should include counter transmission service requests. In WECC, there is currently no virtual schedules and transmission reservations are expected to provide energy flows real-time (or adjustments are made in real-time to ensure ties are not overscheduled). The formula for AFC would look like: AFC=TFC-(TRM*distribution factor) –(CBM*distribution factor)- the sum of(ETC impacts * respective Distribution Factors) + (counter transmission reservations *respective distribution factions). A similar formula could be provided for calculation of ATC.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | |
|---|---|
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| Telephone: | (952) 984-3747 |
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| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☒ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☒ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☒ **MRO** | ☐ | 3 — Load-serving Entities |
| ☒ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☒ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

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|---|---|---|---|
| **Group Comments (Complete this page if comments are from a group.)**<br>**Group Name:**<br>**Lead Contact:**<br>**Contact Organization:**<br>**Contact Segment:**<br>**Contact Telephone:**<br>**Contact E-mail:** | | | |
| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: Phrase "other pending potential uses" too broad and open to interpretation and could allow discrimination. Order 890 states that ETC should include: native load commitments, grandfathered transmission rights, point-to-point reservations, rollover rights, and other **uses identified through the NERC process**. We feel that "other pending potential uses" does not comply with Order 890. All components of ETC should be specifically defined.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☒ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☐ Proposed definition

   ☒ Already approved definition

Comments: But change to, “A designated point, element or group of elements on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.”

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

   ☐ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments:

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☐ No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☒ No

***Comments:***

We disagree with R14, which would require a Transmission Service Provider to require Transmission Customers to provide ultimate source and ultimate sink on Transmission Service Requests and further would require that Transmission Customers must use the same source and sink on Interchange Transaction Tags. Our reasons for not supporting this requirement are several, based on our belief that the requirement (1) is impractical under well-established trading and scheduling practices, (2) has not been shown to be necessary to the reliability of the North American bulk electric system, (3) is not consistent with the Market Interface Principles, which are an integral part of NERC's *Reliability Standards Development Procedure* and (4) conflicts with Order 890. Further, it is not apparent from the records of the draft team's development process that due consideration was given to whether the source/sink requirement adheres to NERC's *Reliability and Market Interface Principles*.

The source/sink requirement is incompatible with the market's trading and scheduling practices. Forward hedging is commonly transacted at Hubs, with the product defined as an "into-*HUB*," (e.g./ into-Entergy). A supplier who delivers energy to an "into-Hub" sale cannot foresee where the buyer will ultimately sink the energy. That supplier may need to purchase transmission to the Hub's interface, but cannot know in advance what sink to input in a Transmission Service Request on an upstream system. Likewise, the buyer does not know the source until the time of day-ahead scheduling, and, therefore, cannot plan his transmission purchases to coordinate with his into-Hub energy purchase. The seller may choose to deliver the "into-HUB" energy at different interfaces day to day.

When scheduling energy flows between regions, the timelines for notifying counterparties of sources/sinks may not be consistent. Though a Purchasing-Selling Entity may learn by 10:00 AM where his purchase is being generated for the next day, he may not know until 11:00 AM where that energy is sinking. The party responsible for transmission in the upstream path may have to submit a Transmission Service Request, due to a transmission provider's timing requirements, before the downstream must declare a sink. So transmission providers' timing requirements may not coincide with scheduling and tagging timelines. Further, characteristics of today's organized electricity markets are not compatible with the proposed source/sink requirement.

When energy is sourced from an organized market (i.e./ LMP system), the actual generating source cannot be identified, as economic dispatch determines generation levels on 5-minute intervals. Thus, for a transaction tagged with a source in an LMP system, the Transmission Service Request and Interchange Transaction Tag may <u>never</u> match. Similarly, in the WECC when a Mid-C product is purchased and taken to delivery, it could be generated at any of numerous hydro-generation facilities, all included in the definition of the Mid-C energy product. The proposed source/sink requirement would put certain market participants at a disadvantage. A Purchasing-Selling Entity who intends to buy transmission to move purchased energy from a Hub to a customer who will transmit the energy downstream beyond the Hub is at the greatest disadvantage with a source/sink requirement. Such a Purchasing-Selling Entity, without known generation or load, may be ignorant of both the source and the sink until the time of scheduling. It is important that the proposed standard is incompatible with trading and scheduling practices. The following is taken from NERC's Reliability Standards Development Procedure: "While NERC reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets."

The MOD-001-1 drafting team recognizes at least two distinct methods for ATC calculations, the Rated System Path Methodology and the Network Response Methodology. The addition of the source/sink requirement in R14, however, seems to ignore the key difference in the two methods. The Rated Path method looks at the capability of the direct wires between two points, and those points are not necessarily the source or the sink. The draft team's records do not disclose claims that the lack of the proposed source/sink requirement has degraded reliability in those systems where the Rated System Path method is employed. Apparently, source/sink requirements such as proposed in R14 are not necessary to the reliability of the North American Bulk Electric system for those areas using the Rated System Path method. In fact, it is documented in the draft team's working papers that source/sink modeling identification is "not relevant for Rated System Path Method for ATC Modeling." (See draft team's document titled NOPRitems.XLS at http://www.nerc.com/~filez/standards/MOD-V0-Revision-RF.html, dated 7/19/06.) The reason for the subsequent addition of the source/sink requirement to the proposed standard cannot be determined from the draft team's records.

The impetus for the development and revision of MOD-001-1 was the Final Report of the Long-Term AFC/ATC Task Force. In that report, in the section titled "Source and Sink Points – Calculation Process for AFC/ATC," is the following statement: "The task force suggests that the sources and sinks (injections and withdrawals) used in the calculation of AFC/ATC and the evaluation of transmission service requests should *replicate* the anticipated use of service when utilized." (Emphasis added.) This statement assumes that requiring source/sink information with a Transmission Service Request and requiring that information to match the Interchange Transaction Tag is <u>not</u> necessary. The next sentence in the report states, "It is important that Transmission Service Providers have business practices outlining when they will allow confirmed transmission reservations to be used in a manner that is not equivalent to how the request for the service was evaluated." Once again, it is granted that source/sink information is not required to match from reservation to tag. And Appendix B of the report states the case even more plainly: "Source and sink points … do not necessarily correspond to the source or sink fields on a transmission reservation, but are constructs that mimic the expected actual change in generation dispatch that would be used to affect that power transfer in real-time."

Further practical considerations show that the R14 source/sink requirement is not necessary to the reliability of the bulk electric system. For instance, Southwest Power Pool (SPP) employs an "electrical equivalent" concept. According to SPP's Business Practices an exception is allowed when the source/sink of a reservation does not match the source/sink of the tag, so long as the source/sink on the reservation is considered electrically equivalent to the source/sink on the tag. SPP also allows an exception when a customer combines two SPP reservations on the same tag, so long as one reservation has the correct source/sink (or electrical equivalent) and the PORs and PODs are contiguous, such a scheduled reservation/tag is valid. (See 4.3 of SPP's Open Access Transmission Tariff Business Practices.) Additionally, consider schedules that flow across DC ties. There is no need, for the purposes of calculating ATC, for transmission providers in the WECC to know where in the Eastern Interconnect a transaction flowing west to east on one of the DC ties is sinking. Likewise, for an energy schedule sourced in ERCOT to a sink in SERC, there is no need for the transmission providers in ERCOT to know the ultimate sink. And no need for the transmission providers in the Eastern Interconnect to know the ultimate source. Source/sink information matching from reservation to tag is not necessary to reliability in these cases.

The proposed source/sink requirement conflicts with NERC's Reliability Standards Development Procedure, which includes two sets of guiding principles, Reliability Principles and Market Interface Principles. "Consideration of the market interface principles is intended to ensure that reliability standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets."

Market Interface Principle 2 states, "An Organization Standard shall not give any market participant an unfair competitive advantage." As mentioned earlier, market participants without known generation resources or load obligations can be put at a definite disadvantage with the proposed source/sink requirement. Market Interface Principle 3 states, "An Organization Standard shall neither mandate nor prohibit any specific market structure." The indirect result of R14 would be to so inhibit markets operated with the Rated System Path Methodology so as to essentially prohibit the prevailing market structure operating where that method is employed. Transmission providers and customers would be forced to transact differently, potentially disrupting long-established and efficient markets. Most importantly, Market Interface Principle 4 states, "An Organization Standard shall not preclude market solutions to achieving compliance with that standard." The title of the standard at issue is *ATC and AFC Calculation Methodologies*. Yet no explanation can be found in the draft team's records as to how the source/sink requirement in R14 will improve ATC calculations. In reviewing the records of the drafting team, no examples can be found showing that the lack of the source/sink requirement causes degraded reliability. In fact, markets that do not require that ultimate source/sink be provided on a reservation and then match on an Interchange Transaction Tag have obviously determined and implemented solutions to calculating ATC, without such a requirement. The record of the drafting team simply does not provide evidence to the contrary.

Finally, in reviewing FERC's Order 890, it is apparent that R14's source/sink requirement is inconsistent with established protocols for transmission service reservations. At paragraph 297 of Order 890 the Commission states, "Regarding transmission reservations modeling, we direct public utilities, working through NERC, to develop requirements in reliability standard MOD-001 that specify (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations." Obviously, it is understood that not only existing reservations may not have provided source/sink information, but also, by distinguishing **existing** reservations, FERC has assumed that future transmission service requests may not provide source/sink information. Indeed the definition of Transmission Service Reservation proposed in the MOD-001-0 standard references Point of Receipt and Point of Delivery, but not source and sink (see 2. at page 4 of this document.)

In summary, the proposed source/sink requirement is inconsistent with established trading and scheduling protocols, is not necessary to the reliability of the bulk electric system, conflicts with the principles established to guide the development of reliability standards and is inconsistent with FERC Order 890. For the reasons stated herein, we disagree with the proposed source/sink requirement in MOD-001-1.

***Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.***

☐ Yes

☐ No

Comments:

~~14.~~13. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

☐ Yes — TTC and TC are the same

☐ No — TTC and TC are not the same

Comments:

~~15.~~14. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

☐ Yes

☐ No

Comments:

~~16.~~15. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

Comments:

~~17.~~16. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

Comments:

~~18.~~17. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Comments:

~~19.~~18. Do you have other comments that you haven't already provided above on the proposed standard?

Comments:

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | |
|---|---|
| Name: | Greg Rowland |
| Organization: | Duke Energy |
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| E-mail: | gdrowlan@duke-energy.com |

| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
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**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for ‘Existing Transmission Commitments (ETCs)’ — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: The definition of ETC is too ill defined. There probably needs to be a separate standard for ETC (as exists for TRM and CBM). "Native load" should be "Network/Native load". All Contingency Reserves has too general to be used for ETC calculation - only reserves considered under TRM and CBM should be allowable for ETC calculation. What are the "existing commitments for purchases, exchanges, deliveries, or sales" that do not fall under the "existing commitments for transmission service" category? This phrase should be eliminated from the definition.

2. This is the proposed definition for ‘Transmission Service Request’ — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments: 'Transmission Service Request' - An OASIS request by the Transmission Customer to reserve transmission capacity for the purpose of moving energy from a point of receipt to a point of delivery.

3. This is the proposed definition for ‘Flowgate’ — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

☐ Already approved definition

Comments: Delete the second sentence of the proposed definition

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☒ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☒ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: Need to define the precise time periods in Operating Horizon and Scheduling Horizon (i.e. 12:00 midnight, etc.)

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments: The definitions of Network Response Method and Rated System Path Method are too vague.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments:

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☐ No

   Comments: Frequency should be as agreed upon or 30 days.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

    Comments: One methodology is sufficient for Duke Energy

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☒ No

    Comments: Delete Requirement 13.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☒ No

    Comments: R11.4 and R11.5 should be moved to FAC-012, since contingencies are modeled in the TTC calculation.

    As written with the requirement to provide ultimate source and ultimate sink, R14 should only apply to reservations and tags on systems that calculate AFC. In general, on systems that calculate ATC or AFC, source and sink granularity on the reservation must be sufficient to allow adequate assessment of the impact on the capacity offering (ATC or AFC). Source and sink granularity on the e-tag must be sufficient to allow adequate assessment of the e-tag's impact on the transmission system. The Point of Receipt (POR) and the Point of Delivery (POD) must be the same on the reservation and the e-tag. If the source or sink on the e-tag is different from the source and sink on the reservation and the impact is substantially different from the expected impact of the reservation, the TP may deny or curtail the e-tag..

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments: See response to Q. #1. TRM, CBM, etc, are defined in other standards

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☐ Yes — TTC and TC are the same

    ☒ No — TTC and TC are not the same

    Comments: FAC-012 should apply to TC, which indicates the ability to reliability move large amounts of power between regions, sub-regions and control areas. Test of TC identifies potential transfer limits that may result from loop flows, market activity or contingencies. TTC calculation is required to support market operation without impacting reliability in a negative manner.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☒ Yes

    ☐ No

    Comments: TFC and AFC need to be in the same standard because they are interlinked with market issues. FAC-012 and FAC-013 focus on calculation of TC for reliability studies.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: Resource Planner should make the calculation.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: TRM should be looked at as a seasonal requirement, and Duke Energy would use the same TRM value for monthly, daily and hourly calculations. Transmission Planner makes the TRM calculation.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: We understand that the drafting team is examining the impacts of FERC Order 890 for conflicts with the proposed standard

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: We have not factored impacts of FERC Order 890 into these comments. Editorial comment on R.12 - should read "Each Transmission Service Provider shall identify other Transmission Service Providers with which the data used in the calculation of ATC or AFC is exchanged."

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: Definition of ETC is broad and can not be used to calculate the ETC in a consistent and reliable manner. Since ETC will vary depending on what ATC calculations this is used for, its components can vary. For example, for Firm ATC calculation, there is no need to include non-firm reservations. A detailed Standard could to be developed or details included in MOD-001 for ETC calculations that should describe requirements and components to be included in ETC calculations. However, in view of para 243 of FERC Order 890, ETC should be addressed by including the requirements in MOD-001 rather than through a separate reliability standard.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☒ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: Time frames (real-time; same day; day-ahead; and from day-ahead up to 13 months) as included in the standard are clear. There is no need to define these terms in this standard as these may conflict with the intent of these terms used in other standards.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments: Definitions of Network Response Method and Rated System Path Method are not clear. It is not clear what is meant by "…customer Demand, generation resources, and the Transmission systems are closely interconnected" in Network Response Method, as they are always closely interconnected. This definition does not reflect that the Transfer Capability is calculated using response of the system or by simulating the impact of flows on the system. The Rated System Path Method appears to be using only the critical path ratings. It is not clear how critical paths are determined and what ratings are used for those. Since there is no difference in calculation of ATCs by either Network Response Method or Rated System Path Method, there does not seem to be any need for including the definition in this standard. If these definitions are applicable only for TTC calculations, these terms should be defined and included in standard dealing with TTC (FAC-012). If included in FAC-012, these definitions should reflect clearly how calculations are performed under each method.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

☐ No

Comments: Since ATC and AFC calculations are performed for selling the Transmission Service (Capability) to customers based on the Open Access Transmission Tariff which is administered by the Transmission Service Provider, it makes sense to assign requirements for ATC and AFC calculations to Transmission Service Providers.

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments: There does not appear to be any difference for ATC calculations for Network Response Method and Rated System Path Method, therefore for the purpose of ATC calculations it does not matter how TTCs are calculated. If the difference will become clear in the TTC calculation method standard, then these definitions and methodologies should be included in that standard (FAC-012) and removed from this standard. There are clearly two methods of Transmission Capability calculations, ATC method and AFC method and only these should be included in the current standard.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

Comments: Calculation and posting of ATC for Constrained Path is included in FERC Order 889 section 37.6(3)(i)(C)(2) as " The capability posted ………. must be updated when transactions are reserved or service ends or whenever the TTC estimate for the Path changes by more than 10 percent. Calculations and posting of ATC for Unconstrained Paths are included in FERC Order 889 section 37.6(3)(ii)(A) as " ….These postings are to be updated whenever the ATC value changes for more than 20 percent. " Therefore, calculation of ATC values on all paths when any of the components changes may not be required. If the ATC is recalculated and not posted it does not do any good. Timing of Posting on OASIS should determine when the ATC and AFC values should be recalculated. Since these timing requirements will be included in NAESB Business Practice Standard there is no need for a requirement R2 in MOD-001 for recalculation of ATC values.

9. Do you agree with the frequency of exchanging data as specified Requirement 6?

☐ Yes

☒ No

Comments: A limit of 7 days does not appear real. The Data Exchange should be on an agreed upon schedule as some data like line and generation outages, if exchanged within 7 days may not be of any use for calculations of real time or day ahead ATCs and AFCs. Since the data is exchanged for coordinating ATCs and AFCs it should be left to the entities that need this information to develop frequency of daa exchange rather than this standard putting some upper limit. In addition, current Requirement 6 applies only to Transmission Service Providers using AFC Method. Data need to be exchanged for ATC calculation also for coordination with the neighboring systems. Several items in Requirement 6 are applicable to ATC calculation such as TTC, ETC etc. This is especially true if a Transmission Provider is using a Network Response Method for calculation of ATC values.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

☐ Yes

☐ No

Comments: Only one method for calculation of ATC or AFC should be used for each system so that there is consistency between the method used for approving transmission service requests and for planning and operation of the system as required in R 11.2. In case more than one method is used it will be difficult to make these methods consistent.

11. Do you think that Requirement 13 in this proposed standard necessary?

☒ Yes

☐ No

Comments: Transmission Service Provider may allocate capability of transmission element to different users based on their ownership interest and any other agreements. This requirement allows use of different ATC or AFC values based on such arrangements. However, it does not have to be limited to only lesser of the calculated value used for approving Transmission Service Request. In case a Transmission Service Provider is using higher than the calculated value (in some emergency cases, TP may use emergency rating of limiting line/equipment which may result in higher than the normal calculated ATC value), it may be putting the reliability of the system at risk. Therefore, the Transmission Service Provider should identify how it determines ATC values for approving Transmission Service Requests if those are different from the calculated values, whether higher or lesser than the calculated value.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments: (R3.) There is no need to include ATC and TTC values to be provided when requested within 7 days as these are expected to be posted on OASIS and be available per OATT requirement. (R4.) The equation assumes that the TRM, CBM and ETC are for each path that has a Distribution Factor factor to each flowgate. Therefore, the language in the standard should be changed to include "respective" before the Distribution Factor for TRM and CBM. In addition, the definition of Distribution Factor included in the NERC Standard Booklet "The portion of Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)" can only be used if the TRM, CBM and ETC are allocated on each Interchange Transaction which is from control area to control area. If the TRM, CBM and ETC standards do not require such allocation, the formula will be invalid. (R5.1) This requirement should also be applicable to ATC calculations if Transmission Service Provider uses impact on interface differently for the Firm and Non-Firm reservation. At a minimum Transmission Service Provider should be required to include method of adjusting the ATCs for Firm and Non-Firm Reservations for transparency purposes. (R5.2) Comment similar to that for R5.1 applies to this requirement as this requirement should be applicable to ATC calculation. (R 5.3) This requirement is poorly written as it is not clear what is required to be on OASIS, Is assumptions used for base case and transfer generation dispatch for both external and internal system need to be on OASIS? If so, it does not make sense. (R6.3) The monitoring of the requirement of exchanging generation dispatch order that is updated at least prior to each peak load season or the generation participation factors of all units on an affected Balancing Authority basis that is updated as required by changes in the status of the unit will be difficult as these are inconsistent. The participation factors theoretically will change any time the generator status changes and will have to be recalculated and shared with all entities. Transmission Service Providers should be required to exchange participation factors when updated and at a minimum prior to each peak load season rather than required to calculate when generator status changes. (R6.8) This requirement is applicable only to AFC calculations as AFC values for different periods need to be updated at certain interval. First this requirement is based on FERC Order 889 and is of commercial nature, therefore, it should be included in NAESB business practices. Secondly, this requirement is also applilcable to ATC values, if it is included in this standard, this should also be made applicable to ATC calculations. (R 6.10) Transmission Service Reservations are available on line on OASIS and need not be included in this standard to be exchanged. Also Transmission Service Reservations may be included in ETC when standard for ETC is developed. (R7) The requirement for updating AFC values should be in NAESB Business Practices. This requirement is also applicable to ATC calculations. (R11) There are more requirements to be included in the AFC methodlogy than the ATC methodology (R5 and R11 are applicable to AFC, and only R11 is applicable to ATC). There does not appear to be a requirement for Transmission Providers using ATC to include items in R1 - R3 in ATC calculation Methodology. It should be made consistent. (R12), (R13), (R14) These requirements can be included in R11 as additional sub requirements. There does not seem to be any justification to keep them as separate requirements and not to be included in the calculation methodology.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☒ Yes

    ☐ No

    Comments: Yes, these details should be included in standard for TTC, TFC, TRM and CBM

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments: TTC and TC are same. However FAC-012 is written for reliabiliy assessment of Bulk System. Since Transfer Capability calculations use same algorithm but different base case models, FAC-012 should be modified to include calculation of TTC that can be used for ATC calculations as described in MOD-001.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☒ No

    Comments: TFC and TTC methodology should be included in the same standard. Since FAC-012 includes TTC, the same standard should include requirements for TFC calculations.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: There can be different CBM for different time horizons. CBM should be calculated based on the uncertainties of generation available within the Transmission Service Provider area to meet loads. Load Serving Entities should calculate CBM for their loads based on their loads and generation available to serve these loads. In case of Reserve Sharing Groups, loads and generation for the entire group should be included to calculate CBM. Or if CBM calculations are performed on a Balancing Authority Area basis, the entire load and genereation in that area should be used for these calculations, even if there are more than one LSEs within that area.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: There can be different TRM for different time horizons. Farther in future, less certain are the conditions, therefore, higher TRM. Since TRM is based on combination of uncertainties of different elements, each components will have different contributions to TRM for different time horizons.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: No, however requirements in the proposed standards should be consistent with those included in FERC OATT, Orders 888, 889, and recently issued FERC Order 890.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: The Standard Drafting Team has a difficult task of including FERC expectation of making ATC calculations consistent and transparent. Due to different operating practices in different regions of the country, it will be difficult to come up with consistent (one size fits all) method. Regional differences should be recognized keeping in view how these are affecting reliability. Any issues that are commercial in nature should be left to NAESB to include in their Business Practices Standards.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
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| Organization: | ERCOT |
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| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☒ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
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**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information

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A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

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- Semi-annual summer and winter TTC values
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- Transmission and generation outage schedules
- Power flow models
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Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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1 http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
2 ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☐ No

   Comments: ERCOT does not have a transmission service market. Therefore, this concept does not have meaning in ERCOT operations as described in this definition.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☐ No

   Comments: ERCOT does not have a transmission service market. Therefore, this concept does not have meaning in ERCOT operations as described in this definition.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☐ Proposed definition

   ☐ Already approved definition

   Comments: ERCOT does not typically use the term "Flowgate". ERCOT analysis considers monitored elements and a list of contingencies used in contingency analysis. However, the definition of monitored element, while similar to Flowgate, does not require the inclusion of associated contingencies. Both definitions, as prescribed, do not have meaning in ERCOT operations.

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☒ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: I am concerned that there may be multiple efforts underway on various SARs and Standards as well as the Operating Limit Definition Task Force that may be using variations of this concept. I do agree that a uniform understanding and set of terms for these timeframes would be useful and may help to avoid contradictions and confusion, but I am uncertain whether this standard is the place for this to be decided. They should not be offered as "definitions", which I understand the standards development process requires to become a part of the NERC Glossary. Perhaps the standard should clarify what is meant for the purposes of this standard, but it should not be proposed as official "definitions" which must apply in all standards.

   In general, I believe that all of the horizons listed, with the exception of the "Scheduling Horizon" exist with some consistency of understanding (although not always with exactly the same durations specified). The Operations Planning "horizon" is typically discussed as representing from Real-Time through Day-Ahead and on up to one year. The "Planning Horizon" is typically discussed as representing one year and longer; this would correspond closely, but not exactly with the "Long-term Planning Horizon" proposed above. Some difficulty arises because many of the differing contractual agreements, organizational arrangements, and market rules define these terms differently at different locations. This may be true even for such arrangements which cross Regions or even Interconnections.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☐ Disagree

   Comments: ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   ☒ No

   Comments: The transmission service provider seems appropriate, however, there is need for a broader oversight or review to coordinate. Without such an "umbrella" there is likely to be differing values calculated by different transmission service providers for the same parts of the transmission system

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

   ☐ No

   Comments: ERCOT does not use these values in its operations.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: ERCOT does not have a transmission service market and does not use this methodology.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☐ No

   Comments: ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

Comments: ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☐ No

    Comments: ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☐ No

    Comments: ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☐ No

    Comments: ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☐ Yes — TTC and TC are the same

    ☒ No — TTC and TC are not the same

    Comments: As I recall, the FAC drafting team recognized similarities, but used a different name because they were not considered to be the same. The FAC standards relate more to operational system capabilities and different timeframes, not to the in-advance nature of TTC used in the transmission service market. The FAC drafting team included in the FAC standards that the TTC methodologies shall respect the System Operating Limits which relate to the TC described in the FAC standards.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments: ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

Comments: ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology. In addition, ERCOT presently has set TRM and CBM to zero in its operating and market activities.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: No.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: Yes. No Regional Differences are identified in this draft. However, ERCOT does not use this methodology and therefore this shall not apply to operating activities and market activities in ERCOT. The standard should provide for ERCOT's non-transaction-based methodology.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

| | |
|---|---|
| **Group Comments (Complete this page if comments are from a group.)** | |
| **Group Name:** | FRCC |
| **Lead Contact:** | **John Odom** |
| **Contact Organization:** | **FRCC** |
| **Contact Segment:** | **10** |
| **Contact Telephone:** | **813-289-5644** |
| **Contact E-mail:** | **jodom@frcc.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Bob Schoneck | FPL | FRCC | 1 |
| Don McInnis | FPL | FRCC | 1 |
| Kiko Barredo | FPL | FRCC | 1 |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☒ Yes

   ☐ No

   Comments:

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☒ No

   Comments: Should specify that it must be done on OASIS and should be broad enough to include network integration transmission service also. Suggested wording: A service requested on the OASIS by a transmission customer of the transmission service provider to move energy out of, across, or into the transmission service provider's transmission system.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments: Last sentense of new definition is not necessary. It is extraneous to the definition.

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☒ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: Requirement R11.5 should use the term " Long-term planning horizon" as defined above rather than " for use in the 13 months and longer time frame".

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☒ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   ☒ No

   Comments: The B.A. and LSE should have obligations to provide the information in R6 i.e. dispatch order, forecasted loads, etc that are applicable.

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments: The standard should allow a Transmission Provider flexibilityto use different methodologies depending on seam and other factors.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: The amount of time needs to correlate with the product and the timeframe effected. For example, an ETC change in future month 8 the length of time to update the posting should be days. If a line trips changing the TTC for the next day then the length of time to update should be hours.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☒ No

   Comments: General requirement of (7) calandar days referenced in general requirement R6 is inconsistant with the individual requirements contained in R6.1.- r6.10 which often reference specfic time frames example R6.10 says " when revised once per hour" or R6.2 that states " as changes occur"

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

   ☒ Yes

   ☐ No

Comments: Different method are needed to address seams issues between areas that select different methodologies, different methods may be applicable to different interfaces etc. The transmission provider should have the flexibility to select the appropriate method.

11. Do you think that Requirement 13 in this proposed standard necessary?

   ☒ Yes

   ☐ No

   Comments: There is a strong reliability need for this. It is believed that the word " posted" needs to be inserted in front of the word value in the statement " other than and less than its value" i.e. the statement should read " other than and less than its posted value".

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☒ Yes

☐ No

Comments:

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments: Separate standards are being developed that address the components

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments: The TTC definition should be retained.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☒ Yes

    ☐ No

    Comments: All transfer related matters need to be contained in one standard not spead out over multiple documents.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments:

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: The TRM should relate to the time horizon of the product. TRM is indtend to account for uncertainties in the bulk electric system and should be determined by the Transmission Service provider. The degree of uncertainty increases in relationship to the product timeframe. The system conditions for hourly are known with a much greater degree of accuracy than for the 13th month. Additionally, the period of exposure to a risk is much greater on a month product than on an hourly product. The probability of a unit or line tripping during the period of a confirmed transaction is much greater for a monthly product than for a daily product.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information** **(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Kevin Conway | | |
| Organization: Grant County Public Utility District #2 of Washington | | |
| Telephone: 509-754-6639 | | |
| E-mail: kconway@gcpud.org | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☒ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: I have no specific suggestions, but in reading the definition for the first time, I am not sure how to interpret this. I have had to read it several times, and could interperet the defintion several ways as to our situation. Dynamic (and or psudo tie) uses for wind, and hydro generation, grandfathered system rights, and flow through from other systems that don't follow schedule paths, but physical paths, could all be problematic.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments: Who's POR or POD? I am sure I know what the intent is, some may read this, as written to mean the whole path.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☐ Proposed definition

   ☒ Already approved definition

Comments: We start to create a problem if standards have their own meanings for a term. This creates an abiguity and needs to be avoided at all costs.

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☒ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: I would avoid the need to create more defined terms. Long lists of defined terms cause confusion and misunderstanding. Perhaps a simpler solution would be to use the term in the text, explain it there when it is first introduced, and then continue to use the term. This makes the document a little easier to read, and keeps the definition in context. It is my experience that in the effort to create a good document, we write at a level that is above many readers comprehension level.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments: I have no problems with the definitions themselves. I do stress again to avoid long lists of defined terms, since they make the document more difficult to read, and comprehend. One other point would be that if these terms are used in other standards, they could be defined slightly different causing confusion.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments: This is consistent with the Functional Model

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path

methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments: However, the standard should be written in a way that if there are other methodologies, now or in the future, they could somehow be accomodated. This thought is based on the concept that the new methodology is defensible.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: Specifying a time is difficult, since it is arbitrary. If the process is automated, it could be immediately. If it is manual, more time is needed. If extensive study is needed, it could take some time, especially if it has to be coordinated with another TSP. It should be as soon as reasonably practicable.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☐ No

   Comments: As long as this is not overly burdensome on smaller TSPs

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

   ☐ Yes

   ☒ No

Comments: Its hard to answer this question without more detail to the ATC calculations.

11. Do you think that Requirement 13 in this proposed standard necessary?

   ☐ Yes

   ☒ No

   Comments: No one would have an issue if the Transmission Service Requests are approved. When they are denied justification needs to be made.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments: "R11.4 Identify the contingencies considered in the ATC and AFC calculation methodology". Is this appropriate? This could be an extensive list in some cases, it could create a security risk, or it could be leveraged for market power.

"R14 The Transmission Service Provider shall require that the Transmission Customer provide both ultimate source and sink on the Transmission Service Request and shall require that that Transmission Customer use the same source and sink on the Interchange Transaction Tags." Shouldn't the TSP only focus on that part of the transmission that he is providing service for? POD and POR? I am not sure if the intent here is to do specific point of generation to point of usage scheduling. If it is, this is not appropriate for our situation. We meet our schedules with a portfolio of generation and meet our loads with a series of contiguous PORs. We do not to be overly specific and burdensome.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments: Being too presciptive will raise issues of entities seeking exemptions for one reason or another, there by confusing the compliance.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments: No opinion.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: The Transmission Operator should be continuously be updating all of these values.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: The Transmission Operator should be continuously be updating all of these values.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: No

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: Thank you for the opportunity to comment. Other comments will arise after further refinement of this standard, and our further study of it.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information** | |
|---|---|
| **(Complete this page for comments from one organization or individual.)** | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☒ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Daniel Soulier | Hydro-Québec TransÉnergie | NPCC | 1 |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☒ Yes

   ☐ No

   Comments: We question the use of "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☒ No

   Comments: Point of receipt and point of delivery shall be defined. Considerations shall be taken for POR and POD from different asynchronous Interconnection

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments: "any associated contingency" needs to be explained. Why should contingencies be associated to an element or group of transmission elements?

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☒ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: Considerations should be made for the transition from the Scheduling and the operating. Exemple transition is performed each day at 16:00

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☒ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☒ Yes

☒ No

Comments: R5, R6, R7 Companion's requirements for Rated system path are not specified

R1 request TTC/TFC being calculate first than

ATC/AFC : TTC/TFC - TRM-CBM-ETC

TSP shall have the possibility to calcualte available Incremental ATC (IATC) ATC/AFC first based on ETC than TTC/TFC should egual:

TTC = IATC+ETC

R9 TSP methodology shall be consistently tied with the "path" and TSP may use different set of assumptions pending the time frame for which the TTC,ATC, etc are calculated

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: will depend on the Time Frame

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider’s entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☒ No

Comments: Methodology choice shall be solely based on the system topology and the path requirements

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☒ Yes

    ☐ No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

☒ No

Comments: refer to 7

R12 – First, this requirement should be placed under R11, because R11 contains the items that must be ‘identified’ in the TSPs ATC methodology

Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:

•“Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC”

Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments: Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments: This question should probably be asked to the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☒ No

    Comments: If TFC is similar to TTC, it should be dealt in another Standard e.g. the same one that would deal with TTC.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: The question is inappropriate, because the standard does not attempt to define the methodology for CBM.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: The question is inappropriate, because the standard does not attempt to define the methodology for TRM.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: The drafting team must engage in additional drafting to address the concerns raised by Order No 890.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
|---|---|
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| Telephone: | 905-855-6187 |
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| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☒ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012. Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☒ Yes

   ☒ No

   Comments: We agree with most of the components except "…other pending potential uses of Transfer Capability". This component is subject to interpretation and it is difficult to demonstrate a quantifiable need for the inclusion of this component. Also, we question the need to specify "exchanges" and "deliveries" given that "purchases" and "sales" are already included in the definition.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☒ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency (ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☒ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☒ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☒ Yes

   ☒ No

Comments: We are not suggesting that the SDT consider other methodologies. However, we do not understand why AFC calculation must be tied with the Network Response methodology only. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.

Hence, we question the need for the qualifying statement – “using a Network Response Methodology” in parentheses, after “calculates AFC” in each of the requirements R4, R5 and R6.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: No more than 1 hour.

9. Do you agree (?) with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☒ No

   Comments: We agree with the frequency of exchanging data as specified in Requirement 6. However, we do not agree with the sub-requirement 6.5.

   Not all TSPs perform load forecasting. They should not be required to provide this information. Beside, load forecast information is already included in the base model a TSP uses in calculating AFCs. This is met by virtue of meeting R6.4.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider’s entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☒ Yes

    ☒ No

    Comments: See comments under Q7 on Rated Path Methodology – AFC (not included in the 3 methods).

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☒ No

    Comments: Requirement 13 is not required. Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue can be addressed in the Business Practice.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments: We do not agree with the following:

(i) The text box next to R5 says: [Please note that it may appear that the AFC methodology contains more requirements than that ATC methodology. Due to the characteristics of the ATC methodology, the corresponding level of detail will be contained in the standard that determines TTC (e.g. FAC 12 or FAC 13) when it is revised.]

We interpret this text box applies to both R5 and R6.

We agree that the two methods are different and therefore may need different detailed requirements in certain aspects. However, many of the sub-requirements in R5 and R6 appear to be applicable to the ATC calculation methodology as well hence the detailed requirements can also be addressed in this standard. Moreover, addressing detailed ATC calculation requirements in FAC-012 or –013 appears to be a misfit since the latter standards deal with Transfer Capabilities (and to be revised to deal with Total Transfer Capabilities as suggested in Q14, below), which are solely reliability parameters. Moreover, having the detailed ATC calculation requirements placed in a separate standard would leave room for confusion to the standard users.

(ii) R6.5. Please see comments under Q9.

(iii) R11.4 The contingencies considered and applied in determining the ATC or AFC would be the same sets used for operating studies and planning studies which could include all possible Category B and Category C contingencies on the TSP's system. It would be near impossible to identify them all. This requirement is implied by R11.2, and where necessary, R11.2 can be expanded to ensure that the ATC and AFC shall be determined with the same set of contingency criteria applicable to the reliability assessment of the like time frame.

(iv) R11.5 We do not understand this requirement. Does it mean that for ATC and AFC calculation, the model and assumptions must be the same as those used for expansion planning? Note that calculations of ATC and AFC need to consider planned outages to BES facilities, whereas expansion planning may not. Also, if this is the requirement, what are the parallel requirements for ATC and AFC calculation in time frames less than 13 months?

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13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☒ Yes

    ☐ No

    Comments: Some general criteria (the basis) for determining CBM and TRM should be developed so that a consistent approach is used by all TSPs.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☒ No

    Comments: TTC and TFC are reliability parameters that are determined by the facility rating methodologies stipulated in FAC-012 and FAC-013, and these values are not determined by the TSP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: All time horizons should be used in accordance with the corresponding ATC calculation time frame. The value of CBM should be determined by the TSP based on the need demonstrated by the LSE.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: All time horizons should be used in accordance with the corresponding ATC calculation time frame. The value of TRM should be determined by the TOP and

RC depending on the reason for the need of interconnection assistance to cover uncertainties that could affect transmission reliability.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: No conflicts. But there are markets that do not provide physical transmission services which require the calculation and posting of ATCs and AFCs. In addition, there are entities that are not under FERC's jurisdiction and hence may not provide any transmission services.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: Requirement 12 should be R11.6

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

| | |
|---|---|
| **Group Comments (Complete this page if comments are from a group.)** | |
| **Group Name:** | ISO RTO Council Standards Review Committee |
| **Lead Contact:** | **Charles Yeung** |
| **Contact Organization:** | **Southwest Power Pool** |
| **Contact Segment:** | **2** |
| **Contact Telephone:** | **832-724-6142** |
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| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| **Alicia Daugherty** | **PJM** | **RFC** | 2 |
| **Mike Calimano** | **NYISO** | **NPCC** | 2 |
| **Ron Falsetti** | **IESO** | **NPCC** | 2 |
| **Matt Goldberg** | **ISO-NE** | **NPCC** | 2 |
| **Brent Kingsford** | **CAISO** | **WECC** | 2 |
| **Anita Lee** | **AESO** | **WECC** | 2 |
| | | | |
| **William Phillips** | **MISO** | **RFC+** | 2 |
| | | **MRO+** | |
| | | **SERC** | |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   X Yes

   X No

   Comments:

   We agree with most of the components except "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion. Also, we question the need to specify "exchanges" and "deliveries" given that purchases and sales are already included.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   X Yes

   No

   Comments:

   The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "and/or A/S" after the word "energy". The SDT should also review the definition of transmission service for consistency.

   The definition should include reference to ultimate Source and Sink. Add to end of proposed definition "… and from ultimate Source to ultimate Sink."

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the

Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Which definition do you prefer?

X Proposed definition

☐ Already approved definition

Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   X N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   We do not agree but if there is a need to reference time periods in the requirements, they should be specified in the requirements themselves and not as universal terms due to the lack of specificity in these.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   X Agree

   ☐ Disagree

   Comments: Remaining definitions: AFC, Network Response Method, Rated System Path Method, TFC, Transmission Reservation are OK.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   X Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating

ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

X No

Comments: We think those are the common used methodologies, we don't know of any others that are widely used.

However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.

Hence, we question the need for the qualifying statement – "using a Network Response Methodology" in parentheses, after "calculates AFC" in each of R4, R5 and R6.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

Comments: We think one day is reasonable in case of TTC, TRM or CBM changes.

If ETC changes, then re-calculation should be done within 1 or 2 hours.

9. Do you with the frequency of exchanging data as specified Requirement 6?

X Yes

☐ No

Comments: While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (ie. Before changes, after a change, after seven days from an agreement) is confusing. Is "as agreed upon" acceptable if it is greater than every seven days?

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

X Yes

☐ No

Comments: We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology.

*E.g. - CAISO currently uses one method on its ties (rated path)to other TSPs and one method for internal (network response). Additionally, for ties if adjacent TSPs use differing methodologies, the rating would not agree, so are we looking at a situation where one methodology may have to be used for each interconnection?*

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

X No

Comments: Approving a request with insufficient AFC might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting a Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is insufficient. This is a common practice and should not have to be documented (justified) after the fact.

It might happen also if a re-dispatch agreement is accepted by a TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by the TP.

Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue should be addressed in the Business Practice.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

X Yes

X No

Comments:

R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study→refused).

R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is the intension then we agree.

R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations? TP's typically exchange Net Interchange based on Schedules and sometimes reservations. However that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.

R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.

R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. The Receiving Entity could update the AFC data on an hourly basis. If the Sending Entity doesn't update the data on an hourly basis, it is not effective.

R11.2 The term "same criteria" is too general, it should be more specific.

R11.4 The term "Identify contingencies" is too general. It is unclear whether this refer to outages or the contingency elements of flow gates.

R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology

Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:

- "Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC"

Data exchanges that is required as part of the TTC calculation should be specified in the TTC Standard.

R14 Over stringent, particularly if AFCs are not calculated to the level or scope of granularity.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    X Yes

    ☐ No

    Comments: NERC should develop some general criteria: What should be included in the TTC, TFC, ETC, TRM, CBM? How should they be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation?

    Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    X Yes — TTC and TC are the same

    X No — TTC and TC are not the same

    Comments: This question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to an operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4 of the Comment Form. We believe TTC should be added into the FAC requirements as a defined term.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    X No

    Comments:

    TTC and TFC are reliability parameters that are determined by the transfer capability methodologies stipulated in FAC-012. These values are not determined by the TSP but by the RC or TOP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments:

    The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments:

    The question is inappropriate, because the standard does not attempt to define the methodology for TRM.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:
    We are not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement, because the proposed language is broad enough to accommodate the manner in which ISOs/RTOs provide transmission service in a market-based environment. As NERC continues to develop Standards to govern reliability practices surrounding the calculation of ATC/TTC/AFC/etc... (and coordinate with NAESB regarding its development of associated business/commercial practices) in response to the Commission directive in Order No. 890, NERC's Standards must be broad enough so as not to frustrate the market-based manner in which ISOs/RTOs provide transmission service.

    As the Commission ruled in Order No. 890 with regard to, among other things, the standardization of ATC calculations, "some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the pro forma OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs."
    See Order No. 890 at P158. The proposed MOD-001 Standard appears to be in line with this direction.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: None

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Kathleen Goodman | | |
| Organization: ISO New England | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☒ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
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**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

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**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   X Yes

   ☐ No

   Comments:

   We agree with most of the components except "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion. Also, we question the need to specify "exchanges" and "deliveries" given that purchases and sales are already included.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   No

   Comments: Definition is already sufficient and should not be expanded or changed.

   The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "and/or A/S" after the word "energy." The SDT should also review the definition of transmission service for consistency.

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   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the

Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Which definition do you prefer?

X Proposed definition

☐ Already approved definition

Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

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   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☒ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   We do not agree but if there is a need to reference time periods in the requirements, they should be specified in the requirements themselves and not as universal terms due to the lack of specificity in these.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   X Agree

   ☐ Disagree

   Comments: Remaining definitions: AFC, Network Response Method, Rated System Path Method, TFC, Transmission Reservation are OK.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   X Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed

changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

X No

Comments: We think those are the common used methodologies, we don't know of any others that are widely used.

However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.

Hence, we question the need for the qualifying statement – "using a Network Response Methodology" in parentheses, after "calculates AFC" in each of R4, R5 and R6.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

Comments: We think one day is reasonable in case of TTC, TRM or CBM changes.

If ETC changes, then re-calculation should be done within 1 or 2 hours.

9. Do you with the frequency of exchanging data as specified Requirement 6?

X Yes

☐ No

Comments: While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (i.e. Before changes, after a change, after seven days from an agreement) is confusing. Is "as agreed upon" acceptable if it is greater than every seven days?

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

X Yes

☐ No

Comments: We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology.

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

X No

Comments: Approving a request with insufficient AFC might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting a Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is insufficient. This is a common practice and should not have to be documented (justified) after the fact.

It might happen also if a re-dispatch agreement is accepted by a TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by the TP.

Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue should be addressed in the Business Practice.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

X Yes

X No

Comments:

R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study→refused).

R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is the intension then we agree.

R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations? TP's typically exchange Net Interchange based on Schedules and sometimes reservations. However that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.

R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.

R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. The Receiving Entity could update the AFC data on an hourly basis. If the Sending Entity doesn't update the data on an hourly basis, it is not effective.

R11.2 The term "same criteria" is too general, it should be more specific.

R11.4 The term "Identify contingencies" is too general. It is unclear whether this refer to outages or the contingency elements of flow gates.

R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology

Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:

- "Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC"

Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.

R14 Over stringent, particularly if AFCs are not calculated to the level or scope of granularity.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    X Yes

    ☐ No

    Comments: NERC should develop some general criteria: What should be included in the TTC, TFC, ETC, TRM, CBM? How should they be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation?

    Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    X Yes — TTC and TC are the same

    X No — TTC and TC are not the same

    Comments: This question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to an operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4 of the Comment Form. We believe TTC should be added into the FAC requirements as a defined term.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    X No

    Comments: TTC and TFC are reliability parameters that are determined by the transfer capability methodologies stipulated in FAC-012. These values are not determined by the TSP but by the RC or TOP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments:

    The question is inappropriate, because the standard does not attempt to define the methodology for TRM.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: We are not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement, because the proposed language is broad enough to accommodate the manner in which ISOs/RTOs provide transmission service in a market-based environment. As NERC continues to develop Standards to govern reliability practices surrounding the calculation of ATC/TTC/AFC/etc... (and coordinate with NAESB regarding its development of associated business/commercial practices) in response to the Commission directive in Order No. 890, NERC's Standards must be broad enough so as not to frustrate the market-based manner in which ISOs/RTOs provide transmission service.

    As the Commission ruled in Order No. 890 with regard to, among other things, the standardization of ATC calculations, "some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the pro forma OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs."

    See Order No. 890 at P158. The proposed MOD-001 Standard appears to be in line with this direction.

19. Do you have other comments that you haven't already provided above on the proposed standard?

Comments: None

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
|---|---|
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| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

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| **Group Comments (Complete this page if comments are from a group.)** |
| **Group Name:** |
| **Lead Contact:** |
| **Contact Organization:** |
| **Contact Segment:** |
| **Contact Telephone:** |
| **Contact E-mail:** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: "Other pending potential uses" does not sound like an existing commitment. The definition should reference "other uses" or "other pending uses" or "other committed uses" but a "potential use" is not a commitment. There are lots of potential uses of the transmission system, but the only ones that matter in the context of this definition are those for which transmission capacity needs to be reserved.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments: It may be semantics, but NITS generally does not have "a point" of receipt or delivery. The definition could refer to sources and sinks rather than PORs and PODs.

   Also, why is this term being defined? It is virtually identical to the definition of Transmission Service, only with the phrase "provided to" replaced by "requested by." The Standards should not define the obvious.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Which definition do you prefer?

☒ Proposed definition

☐ Already approved definition

Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☒ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: For bettor or for worse, the Standards are now using violation mitigation time horizons. These include time horizons for "Long Term Planning," "Operations Planning," "Same Day Operations," "Real-Time Operations," and "Operations Assessment." The Transmission Planning Standards (notably TPL-001 through -004) have also had a near-term and a longer-term planning horizon to further segment the Long-term Planning Horizon. Rather that create yet another set of time horizons for this standard, NERC should consider standardizing the time horizons, or at least re-using some of them when they could suffice for a particular scenario. In this instance, it appears that the time horizons for MOD-001 could be made to work with the Time Horizons for violation mitigation with only a little bit of tweaking.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☒ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team

consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☒ Yes

☐ No

Comments: The drafting team should consider other methodologies if they are aware of any entities using another methodology and achieving reliable results.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments:

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☒ No

    Comments: The requirement is curious. If a service request is approved, who cares if the Service Provider used an ATC/AFC lower than its posted ATC/AFC? I'd be more concerned about a TSR that was rejected because of a lower ATC/AFC, and would want to know how the TSP calculated the lesser value.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☒ Yes

☐ No

Comments:

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments:

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments:

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments:

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Michael Gammon | | |
| Organization: Kansas City Power & Light | | |
| Telephone: 816-654-1242 | | |
| E-mail: mike.gammon@kcpl.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☒ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☒ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: This definition is open ended. It would be better as a definition to include all components that can be thought of and amend the definition as the need arises. This definition needs to stand alone and not make reference to TRM and CBM. If there are items missing from the TRM and CBM that need to included in them, then it should be included and not left for ETC to clean up.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☒ No

   Comments: This definition has already been adopted in the current NERC Glossary and is sufficient.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments: Propose the following refinement to the proposed definition:

Flowgate - a single transmission element or group of transmission elements that may include an associated transmission contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage by the use of Transfer Distribution Factors.

Transmission Distribution Factor is not included in the NERC Glossary. Should Transmission Distribution Factor be defined or should it be excluded from the above definition?

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☒ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments: Available Flowgate Capacity: The definition should end at "Existing Transmission Commitments". If "retail customer service" should be included in ETC, then it should be in the definition and subsequent reliability standards for the development of ETC.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: Recalculation of ATC may be in the OATT agreements and is not needed here.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☒ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☒ Yes

    ☐ No

    Comments: Please consider changing "identify how it calculated" to "provide the basis for calculating" in the R13 Reliability Standard. I think it is more important to know why the value changed rather than how the value changed.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☒ Yes

    ☐ No

    Comments:

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☒ Yes

    ☐ No

    Comments: The purpose of the MOD Reliability Standards is to provide the "how to" for modeling and determining operating parameters. The purpose of the FAC Reliability Standards is to provide "you will use" the results of the MOD to operate the bulk electric system. TFC methodology should be defined in the MOD and then how it is used in the FAC.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: MOD-004-0 R1.2 already requires that the frequency for CBM updates be identified by the Regional Reliability Organinzation and its members and it should be left that way. CBM should be used in all time horizons.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: MOD-008-0 R1.1 already requires that the frequency for TRM updates be identified by the (a) Regional Reliability Organinzation and its members and it should be left that way. TRM should be used in all time horizons.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: No.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: No.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Allan Silk, P. Eng. | | |
| Organization: Manitoba Hydro | | |
| Telephone: 204-487-4480 | | |
| E-mail: adsilk@hydro.mb.ca | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☒ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☒ | 5 — Electric Generators |
| ☐ **SERC** | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

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| **Group Comments (Complete this page if comments are from a group.)** |
| **Group Name:** |
| **Lead Contact:** |
| **Contact Organization:** |
| **Contact Segment:** |
| **Contact Telephone:** |
| **Contact E-mail:** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: Manitoba Hydro believes that the definition is close but you would have to develop the definition further to describe when it is appropriate to describe reserves as ETC.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☒ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☐ Proposed definition

   ☒ Already approved definition

   Comments: Between the two definitions the second is clear enough to be used in a standard. Manitoba Hydro believes you could work on the proposed definition to improve it without changing the meaning. For example, the phrase "model MW flow impact relating to transmission limitations and transmission service usage" could be replaced with "model congestion through all Horizons"

I suggest that the team has erred in including the contingencies in the definition of the flowgate. The contingency may define what type of flowgate it is, e.g. OTDF as compared to PTDF, and will certainly define where the location of the flowgate is but it does not define what a flowgate is. A flowgate could be created by a planned/forced transmission outage, a planned/forced generator outage, or a by an interregional stability concern. It may be good practice to include the contingency in the naming of flowgates, e.g. x for loss of y, but in my opinion y is not part of the flowgate.

In defining a flowgate as a single transmission element or a group of transmission elements, I believe the team would be doing a great service to the industry by determining if one type of flowgate, single transmission element or group of transmission elements, is preferable. There is a concern that multi-facility flowgates provide less overall reliability (by their proxy nature) than single element flowgates. The team should also determine if and when it is appropriate to use proxy flowgates.

Finally I believe "that Transfer Distribution Factors are used to approximate MW flow on a Flowgate… " is actually a second definition (Flowgate Impact). The information is useful but extraneous when defining what a flowgate is.

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☒ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: In the Operations Planning Horizon, I believe that the word "up" should be removed. It is important to coordinate the length of the Horizons. This will allow all transmission providers to use simular assumptions when studying congestion on flowgates.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☒ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments: I think it is of paramount importance that only one methodology is used within an interconnection (i.e. the east and the west can use different methodologies but within each interconnection should only use one methodology). My reasoning for this is is tied to consistent assumptions. Each transmission privider will develop and study flowgates using a single methodology. If a neighbouring transmission provider is studying inpacts on that flowgate using a different set of assumptions or methodolgy then reliability would be inpacted.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: In an automated system, why wouldn't this be immediately (or as soon as the information is loaded into the system that calculates ATC/AFC

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

Comments: Requirement 9 should be interconnection wide. TSPs do not only calculate ATC on their own systems, they calculate inpacts on a set of flowgates on neighbouring systems. Using a differing methodology would needless impact reliability on those systems.

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☐ No

    Comments: It is hard to say as requirement 13 seems unclear

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

☐ No

Comments:

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☐ No

    Comments: With CBM I believe that the only reliability portion is the recognition of an adeqacy criteria (i.e. the LOLE study) Once that is established CBM could be defined many ways and is likely in the realm of NAESB

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☒ No

    Comments: I think that the team was well advised to defer this to the facility rating standard team. However a flowgate can be defined by single or multi elements. the team should ensure that the team developing FAC-012 and/or FAC-013 is cover both as well.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: I believe this and other features of CBM should be determined by NAESB

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: This would depend on the need for TRM. IF TRM is required to coordinate interregional stability concerns, it may needed in all horizons. If TRM is used to compensate for uncertainty in Load Forecasts, it should not be used in the operating or day ahead horizon.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: It is of paramount that a standard is developed that standardizes assumptions and processes. There are many reasonable processes available to develop and study impacts on flowgates. If all transmission providers would be able to contain all the impacts from their operation on their systems, there would not bee the need for this standard. Each transmission provider could use what ever set of assumptions that the wished as long a reliability on their system was maintain. But the very fact that this is not possible to contain impacts requires standardization of assumptions and processes. This is required to insure that when a transmission provider is assessing the impact on a flowgate in a neighbouring system that the assumptions used to assess the impacts are the same assumptions used to develop and study the flowgate. This can only be done if every transmission provider is using one set of assumptions and on set of processes.

    It appears by what has been presented here that the team is trying to accommodate various processes that are used by the industry today. In my opinion, this can only be done by compromising the reliability.

    It also appears (and I may be wrong) that the team has not fully come to terms with what is a reliability concern and what is a commercial concern. For example, in my opinion, CBM is mostly a commercial concern. CBM has historically been used to account for shortfalls in adequacy studies. I am the first to admit that this is purely a reliability concern. However once the adequacy study has determined the shortfall, there are many methods of mitigating that shortfall ranging from simply putting a CBM value on the ties with your neighbour who is most likely to have excess capacity when you need it to belong to a capacity reserve sharing pool that will reserve transmission through the use of CBM. The only reliability concern in all of this is the identification of the adequacy concern and need to have a posting value to mitigate the adequacy concern. The commercial concerns of how to mitigate those concerns should be left to NAESB.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Jerry Tang | | |
| Organization: Municipal Electric Authority of Georgia | | |
| Telephone: 770-563-8190 | | |
| E-mail: jtang@meagpower.org | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

| |
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| **Group Comments (Complete this page if comments are from a group.)**<br>**Group Name:**<br>**Lead Contact:**<br>**Contact Organization:**<br>**Contact Segment:**<br>**Contact Telephone:**<br>**Contact E-mail:** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

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If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☐ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

   ☐ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments:

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☐ No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☐ No

    Comments:

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☐ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments:

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: Since CBM is a reliability margin, the long term or annual value should be used for the monthly, daily and weekly ATC calculations. It should be calculated by LSE.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: Since TRM is a reliability margin, the long term or annual value should be used for the monthly, daily and weekly ATC calculations. It should be calculated by TP.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| **X MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | X | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

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| **Group Comments (Complete this page if comments are from a group.)**<br>**Group Name:**<br>**Lead Contact:**<br>**Contact Organization:**<br>**Contact Segment:**<br>**Contact Telephone:**<br>**Contact E-mail:** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

General MidAmerican Comments

Since the first draft of reliability standard MOD-001-1 was posted for comment on February 15, the Commission has issued Order No. 890. Order No. 890 imposes a number of specific requirements on this reliability standard. MidAmerican does not believe the standard, as currently drafted, meets the requirements of Order No. 890 and that significant modifications will be required before another draft is issued. Order No. 890 includes the following specific provisions related to MOD-001:

- In order to have consistent posting of the ATC, TTC, CBM, and TRM values on OASIS, we direct public utilities, working through NERC, to develop in the MOD-001 standard a rule to convert AFC into ATC values to be used by transmission providers that currently use the flowgate methodology. (Paragraph 211)

- We expect that NERC will address ETC through the MOD-001 reliability standard rather than through a separate reliability standard. By using MOD-001, the ETC calculation can be adjusted to be applicable to each of the three ATC methodologies under development by NERC. (P 243)

- ETC should be defined to include committed uses of the transmission system, including (1) native load commitments (including network service), (2) grandfathered transmission rights, (3) appropriate point-to-point reservations, (4) rollover rights associated with long-term firm service, and (5) other uses identified through the process. (P 244; footnote 170 defines "appropriate" point-to-point reservations to mean that "reservations accounted for under ETC depend on the firmness and duration of the reservation," with the specific characteristics to be developed in the reliability standard.)

- ETC should not be used to set aside transfer capability for any type of planning or contingency reserve, which are to be addressed through CBM and TRM. In addition, in the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC. (P 244; footnote 171 defines TRM to include "such things as loop flow and parallel path flow.")

- Reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at POR…. We direct public utilities, working through NERC, to develop requirements in MOD-001 that lay out clear instructions on how these reservations should be accounted. (P 245)

- We direct public utilities, working through NERC, to develop consistent requirements for modeling load levels in MOD-001 for the services offered under the pro forma OATT. (P 295)

- We direct public utilities, working through NERC, to develop requirements in NERC's MOD-001 reliability standard specifying how transmission providers shall determine which generators should be modeled in service, including guidance on how independent generation should be considered…. We direct public utilities, working through NERC, to revise reliability standard MOD-001 by specifying that base generation dispatch will model (1) all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run and (2) uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements. (P296)

- We direct public utilities, working through NERC, to develop requirements in reliability standard MOD-001 that specify (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations. (P 297)

- The Commission thus directs public utilities, working through NERC and NAESB, to revise reliability standard MOD-001 to require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, e.g., generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities. (P 301)

Responses to Specific Questions

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   X No

   Comments: The definition of ETC must be modified to comply with Order 890, Paragraph 244. In addition, the definition does not define "other pending potential uses" of Transfer Capability, or explain how the other individual components of ETC are to be calculated.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   X No

Comments: This is not a proposed definition. This is the current definition in the NERC glossary.

The new definition should defines the transmission service request as a request for transmitting capacity and energy.

3. This is the proposed definition for ‘Flowgate’ — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   X Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   X N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don’t agree with the proposed definitions

   Comments:
   MidAmerican is unable to find any of these terms in the standard as it’s currently drafted.

   If these terms are used in the standard, these terms should be revised to use 12 months or longer to refer to the long-term planning horizon and operations planning horizon for up to 12 months as used in other standards such as TPL-001 through TPL-004.

To the extent these terms *are* used in the standard, we believe the resolution of this question should be deferred until the standard is redrafted to be compliant with order No. 890.

If the proposed definitions are retained, it would appear that new definitions would be required for these terms:

- day-ahead
- real-time (Although this term is already defined in the NERC Glossary of Terms, the intent in MOD-001 may not match that existing definition.)
- same-day
- 13 months (This should be changed to 12 months to be consistent with the definition that is being clarified by TPL-001 through TPL-004.)

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   X Agree

   ☐ Disagree

   Comments: The AFC definition is acceptable, but the equation in R4 does not match the definition. The equation in R4 should read:

   ATC = TTC – TRM – CBM – ETC

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   X Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☒ Yes

   X No

Comments: It should require that each of the three methodologies be standardized such that any provider utilizing that methodology can duplicate the results from the input data.

8. In Requirement 2, the Transmission Service Provide[r] that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: The timing requirements of R2 should be the same as the timing requirements of R7.

9. Do you [agree] with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   X No

   Comments: In the Eastern Interconnection, the timing requirements of R6 should match the related timing requirements of the MISO/MAPP/PJM/SPP/TVA SOAs/JOAs.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☒ No

    Comments: A single methodology should be required not only within each TSP's system, but across a larger footprint, such as an RRO.

11. Do you think that Requirement 13 in this proposed standard necessary?

    X Yes

    ☐ No

    Comments: The phrasing of R13 should be clarified. As currently drafted, it reads:

    > If the Transmission Service Provider approves a Transmission Service Request using a value other than and less than its value for ATC or AFC, then the Transmission Service Provider shall identify how it calculated the lesser value.

    MidAmerican believes this is intended to mean, and should be clarified to say:

    > If the Transmission Service Provider denies a Transmission Service Request for less than its value for ATC or AFC (or for less than its share of ATC or AFC on reciprocal coordinated flowgates), then the Transmission Service Provider shall identify why the service was denied. This calculation methodology should also be posted.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

X No

Comments: As noted in our General Comments above, MidAmerican does not believe the standard as currently drafted complies with FERC Order No. 890.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    XYes

    ☐ No

    Comments: See General Comments above. In addition to changes required to comply with Order No. 890, the process should be standardized and transparent to the point that another provider, using the same methodology and input data, could duplicate the results of any provider.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☐ Yes — TTC and TC are the same

    X No — TTC and TC are not the same

    Comments:

    Given the new requirements in Order No. 890, the definitions TTC and TC must be consistent since Order No. 890 requires consistent methodologies for use in i) planning, and ii) ATC or AFC calculations.

    It should be noted that TC is used for planning and security coordination purposes, while TTC is commercial in nature and must be updated with each ATC calculation to reflect operational conditions. As a result, there may be points in time when TC is not equal to TTC due to the frequency of updates.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    X Yes

    ☐ No

    Comments: MOD-001 should address the methodology and documentation.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: The TSP should calculate the CBM and the timing and methodology should be well documented.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: The TSP should calculate the TRM and the timing and methodology should be well documented.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: See General Comments above. FERC Order No. 890 makes the current standard obsolete and it must be significantly revised.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: See General Comments above. FERC Order No. 890 makes the current standard obsolete and it must be significantly revised.

    In addition, each of the three methodologies should address contract path limitations. Not only should each methodology address physical limitations of the system, but contractual limitations as well.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Renuka Chatterjee | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
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| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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| **Group Comments (Complete this page if comments are from a group.)**<br>**Group Name:**<br>**Lead Contact:**<br>**Contact Organization:**<br>**Contact Segment:**<br>**Contact Telephone:**<br>**Contact E-mail:** | | | |
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## Background Information

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A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: The definition for ETC is very generic. With the FERC Order 890 requirements of transparency in ATC/AFC calculations, this definition needs to be revisited to add more speficity to it. The definition specifically needs to include modeling of transmission commitments due to transmission service from other transmission providers. Midwest ISO is currently addressing this through two approaches – 1. Seams agreements that address modeling of transmission commitments from other entities. 2. a forecast error term which is currently under development that will address AFC predictions in real time to accommodate for errors in load, generation outage and loopflow forecasts. The standard needs to be revisited to make the computation of transmission commitments in both AFC and ATC methodologies transparent to transmission customers. Include thirdy party generation to load impacts.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments: This definition itself would have been fine if the terms "Point of Receipt" and "Point of Delivery" were consistently treated by the various transmission providers. With the FERC order 890 requirements of consistency in AFC/ATC calculations, the standards needs to be revisited to address the consistent and transparent treatment of Point of Receipt, Point of Delivery, Source and Sink usage as applicable to a TSR within AFC/ATC calculations. A suggested industry wide definition for Transmission Service Request could be "a request for using the transmission system submitted to a transmission provider (typically through an OASIS system) to move power (MWs) either into, out of, within or across the footprint of the transmission provider (with specific start time and stop times, class of service (firm/nonfirm) and service increment (hourly,daily weekly etc.,)"

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer

Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Which definition do you prefer?

☐ Proposed definition

☐ Already approved definition

Comments: Neither - The proposed definition and NERC definition creates the impression that any set of transmission elements could be used to make up a flowgate resulting in inconsistencies in flowgate usage between selling transmission service and curtailing transmission service. "Flowgates are pre determined set of constraints on the transmission system that are expected to experience loading problems in real-time. " This should result in neighbouring transmission providers using consistent set of flowgates for evaluating transmission service. The requirements should address making this list of flowgates and their parameters transparent

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☒ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: These terms and frequency of calculations are business practices of each individual transmission provider. Defining these terms in the standard and only transmission providers using Network Response Method (AFC/ATC) calculations does not appear to be consistent with Order 890 requirements of consistency. The requirements should more along the lines of allowing each Transmission provider irrespective of the methodology used to make available business practices that describe the time horizons and frequency of calculations.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments: The definitions do not include TTC and ATC. All definitions related to this standard should be in a single place (TFC and AFC are defined). The Rated System Path method and the Network Response Method are both approaches for facilitating the processing of Transmission Service Request and need to be measured against similar requirements.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments: The standard is very generic for the ATC methodology/rated system path method. The standard does not provide for transparent and consistent computation of ETC which is the biggest driver in ATC/AFC calculations.To address the Order 890 requirements of consistency and transparency, the standard needs to be methodology neutral.

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☒ Yes

☐ No

Comments: Same comment as previously; to address the Order 890 requirements of consistency and transparency, the standard needs to be methodology neutral.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

Comments: The calculation frequency should be the same regardless of the calculation methodology

9. Do you with the frequency of exchanging data as specified Requirement 6?

☐ Yes

☒ No

Comments: The frequency does not allow for any analysis before the ATC/AFC values are posted to the OASIS. The requirements should be more along the lines of using same ATC/AFC values and providing the same to the neighbouring transmission providers

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

☐ Yes

☐ No

Comments: If the questions is one method only for one TP, the answer is no. Due to contract obligations between transmission providers, there is a need to maitain a few contract paths while maintaining Network response method for AFC/ATC calculations.

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

☒ No

Comments: This requires policing the tags after the fact, and really has nothing to do with the calculation of ATC/AFC.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments: The standard needs to be revisited in light of the Order 890 to make sure consistent measures are applied to all calculations.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☒ Yes

    ☐ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☒ No

    Comments: As explained earlier, the standard needs to be methodology neutral

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: These parameters are individual transmission providers business practices.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: These parameters are individual transmission providers business practices.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: The FERC order 890 calls for more transparency in the AFC/ATC calculations. This standard did not seem to focus on that aspect, in fact, it gives two different standards for transparency: ATC methods have no transparency, and AFC methods are completely open. In light of the goals expressed in FERC's final rule on this issue, for both transparency and consistency of calculation, the committee should withdraw this proposal and review it carefully in light of FERC's Order 890 While the committee has worked hard to bring the standard to this point, Midwest ISO believes this issue is too important to simply forge ahead without discussing the standard's present definitions and requirements in light of the FERC final rule on this subject, issued the same day this standard was released for comment.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: The standard include formulas. The formulas should be left to the business practices of the provider and the terms

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information** **(Complete this page for comments from one organization or individual.)** | |
|---|---|
| Name: | Michael Brytowski |
| Organization: | MRO |
| Telephone: | 651-855-1728 |
| E-mail: | mj.Brytowski@midwestreliability.org |

| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☒ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☒ | 10 – Regional Reliability Organizations, and Regional Entities |

| | | | |
|---|---|---|---|
| **Group Comments (Complete this page if comments are from a group.)** | | | |
| **Group Name:** | **NSRS** | | |
| **Lead Contact:** | **Carol Gerou** | | |
| **Contact Organization:** | **MRO** | | |
| **Contact Segment:** | **10** | | |
| **Contact Telephone:** | **218-722-1972 ext. 2058** | | |
| **Contact E-mail:** | **cgerou@mnpower.com** | | |
| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
| **Neal Balu** | **WPSR** | **MRO** | 10 |
| **Terry Bilke** | **MISO** | **MRO** | 10 |
| **Al Boesch** | **NPPD** | **MRO** | 10 |
| **Robert Coish, Chair** | **MHEB** | **MRO** | 10 |
| **Carol Gerou** | **MP** | **MRO** | 10 |
| **Ken Goldsmith** | **ALT** | **MRO** | 10 |
| **Todd Gosnell** | **OPPD** | **MRO** | 10 |
| **Jim Haigh** | **WAPA** | **MRO** | 10 |
| **Pam Oreschnik** | **XCEL** | **MRO** | 10 |
| **Dick Pursley** | **GRE** | **MRO** | 10 |
| **Dave Rudolph** | **BEPC** | **MRO** | 10 |
| **Eric Ruskamp** | **LES** | **MRO** | 10 |
| **Tom Mielnik** | **MEC** | **MRO** | 10 |
| **Larry Brusseau** | **MRO** | **MRO** | 10 |
| **Michael Brytowski, Secretary** | **MRO** | **MRO** | 10 |
| **27 Additional MRO Members** | **Not Named Above** | **MRO** | 10 |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: a. It is not clear in the definition whether the words existing commitments is to apply only to purchases or also exchanges, deliveries, or sales. In other words, is it the intent of the Drafting Team that only existing commitments for exchanges, deliveries, or sales be included in ETC? If it is the latter than the definition should be changed to say existing commitments for exchanges, existing commitments for deliveries, or existing commitments for sales or else use punctuation such as semi-colons to make clear the meaning. If it is the former than the MRO suggests that exchanges deliveries, or sales be moved before the words existing commitments for purchases, such as exchanges, deliveries, or sales, existing commitments for purchases, existing commitments for transmission services, etc.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments: The OATT definition for Point-To-Point Transmission Service indicates that it is a service for the receipt of capacity and energy at designated Points of Receipt and the transmission of such capacity and energy to designated Points of Delivery. The definition of Transmission Service Request should be revised to state that it is a request to move CAPACITY and energy from a Point of Receipt to a Point of Delivery. The added word is stated in all caps.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the

Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Which definition do you prefer?

☒ Proposed definition

☐ Already approved definition

Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☒ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: These terms should be used consistently across the standards and inserted in the NERC glossary. Having individual definitions in an individual standard will only lead to confusion. The Operations Planning Horizon should be less than one year. Other NERC standards such as TPL-001 through TPL-004 are established assuming that one year or more falls into the Long-term Planning Horizon.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments: a. The definition for AFC and ETC does not specifically refer to market flows. Are these considered a part of ETC or are they not to be included in the calculation of AFC? Please clarify where these are to be dealt with in the calculations. b. There is no specific reference to confirmed or non-confirmed transmission reservations in either AFC or ETC. Are these to be included in ETC? Please clarify the definitions in regard to such reservations.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☒ Yes

   ☐ No

   Comments: Contract Path Methodology should be considered.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: Once the TSP is aware that something has changed, then the TSP has to determine what changes in the components are appropriate via analysis which is often times off-line, then changes are perhaps incorporated into an automatic process for ATC postings. From the question it is the MRO's opinion that the Drafting Team is interested in getting a reading on the time required to post a change in ATCs once the amount of component change is determined. The entire process from the time that it is clear that a component needs to be changed to when new ATCs are posted typically takes two weeks. The time once the changes in the components are determined is typically a one day process. It is presumed that the latter time frame is the time frame in which the Drafting Team is interested.

9. Do you agree with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☒ No

   Comments:

   If the Transmission Service Reservation information can be provided every hour why can not the requirements of R6.5, R6.6, and R6.7 be revised to provide hourly reporting as well?

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

Comments: Transmission Service Provider may use contract Path methodology in addition to one of the methods provided in the proposed NERC standard.

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☒ Yes

    ☐ No

    Comments:

    Helps transparency.

    While this may help transparency how does using a lower value relate to reliability? This seems to be an OATT business practice issue.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☒ Yes

    ☐ No

    Comments:

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☐ Yes — TTC and TC are the same

    ☒ No — TTC and TC are not the same

    Comments:

    Typically, when determining transmission service the Total Transfer Capability (TTC) and the Transfer Capability (TC) are the same (when referencing to standards FAC-012-1 and/or FAC-013-1); however, there may be operating situations where these parameters are not the same. For example, the TC to be used in an operating guide may not be equal to the TTC that would be offered as transmission service.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments: Both MOD-001-1 and FAC-012-1 should reference the flowgate capability.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: At least calculate hourly CBM values for applicable entity TSP.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: At least calculate hourly TRM for applicable entity TSP.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: No.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

    a. With FAC 010, 011,012, and 013 why is MOD-001-1 needed for reliability? MOD 001-1 seems to be an OATT business practice issue.

    b. Informational references to the corresponding development of NAESB business are irrelevant in the Canadian context as Canadian jurisdictions are not obligated to follow NAESB business practices.

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Matt Schull | |
| Organization: | North Carolina Municipal Power Agency #1 | |
| Telephone: | 919-760-6312 | |
| E-mail: | mschull@electricities.org | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
| ☐ FRCC | ☐ | 2 — RTOs, and ISOs |
| ☐ MRO | ☐ | 3 — Load-serving Entities |
| ☐ NPCC | ☐ | 4 — Transmission-dependent Utilities |
| ☐ RFC | ☒ | 5 — Electric Generators |
| ☒ SERC | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ SPP | ☐ | 7 — Large Electricity End Users |
| ☐ WECC | ☐ | 8 — Small Electricity End Users |
| ☐ NA – Not Applicable | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments: A Transmission Service Request is a request to reserve Transmission Capacity. If accepted and confirmed, it is not necessary for the Transmission Customer to move energy on this Transmission Capacity. In fact, it may be used for operating reserves and energy would only be scheduled on this capacity if there was an emergency. The definition should read in a manner that the Transmission Customer is requesting Transmission Capacity from a point of receipt and points of delivery.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☐ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

    **Operating Horizon** — Time frames encompassing same-day and real-time periods.

    **Scheduling Horizon** — Time frames encompassing the day-ahead period.

    **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

    **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

    Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

    ☐ N/A — these terms do not need to be defined for use in this standard

    ☒ The terms do need to be defined and I do agree with the proposed definitions

    ☐ The terms do need to be defined but I don't agree with the proposed definitions

    Comments: Should the Scheduling Horizon be defined as "Time frames encompassing the ***business*** day-ahead period"? Most transmission customers schedule on Friday for Saturday, Sunday and Monday deliveries. Also, some transmission provider OASIS business practices recognize business days rather than calendar days. (e.g. Some TPs sell non-firm hourly transmission after noon for the next business day, which on Friday includes Saturday, Sunday and Monday.)

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

    ☐ Agree

    ☐ Disagree

    Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

    ☒ Yes

    ☐ No

    Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed

changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☐ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: ATC should be recalculated as soon as practical with the goal of getting the most accurate information to the market as quickly as possible. I would expect that most of these calculations are automated, and a change in any component would prompt an immediate recalculation and posting of ATC.

9. Do you agree with the frequency of exchanging data as specified in Requirement 6?

   ☐ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☒ Yes

    ☐ No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☒ No

    Comments: R14 should be eliminated. The proposed source/sink requirement is inconsistent with established trading and scheduling protocols, is not necessary to the reliability of the bulk electric system and conflicts with the principles established to guide the development of reliability standards. Requiring the same ultimate source and ultimate sink on the Transmission Service Request and the Interchange Transaction Tag will harm commercial use of transmission service. It will force transmission users to redirect transmission service on OASIS every time a source or sink changes, even in cases where the source/sink combinations are electrically equivalent. This new practice will provide little, if any, benefit for reliability.

If the drafting team feels this requirement is still needed, it should be passed to NAESB for inclusion as a business practice.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

☐ Yes

☐ No

Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

☐ Yes — TTC and TC are the same

☐ No — TTC and TC are not the same

Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

☐ Yes

☐ No

Comments:

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

Comments: In determining ATC for the different time horizons the CBM must match the same time horizon. The primary responsibility of the CBM for the Hourly ATC will be the LSE to meet its responsibility of providing all energy and capacity for load, including operating reserves for the upcoming hours.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: In determining ATC for the different time horizons the TRM must match the same time horizon. The planners that plan at the different time horizons would be the best.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☒ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☒ | 10 – Regional Reliability Organizations, and Regional Entities |

| | |
|---|---|
| **Group Comments (Complete this page if comments are from a group.)** | |
| **Group Name:** | NPCC CP9, Reliability Standards Working Group |
| **Lead Contact:** | **Guy V. Zito** |
| **Contact Organization:** | **Northeast Power Coordinating Council** |
| **Contact Segment:** | **10** |
| **Contact Telephone:** | **212-840-1070** |
| **Contact E-mail:** | **gzito@npcc.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Kathleen Goodman | ISO-New England | NPCC | 2 |
| Greg Campoli | New York ISO | NPCC | 2 |
| Biju Gopi | The IESO | NPCC | 2 |
| Guy Zito | Northeast Power Coordinating Council | NPCC | 10 |
| Ed Thompson | ConEdison | NPCC | 1 |
| Ralph Rufrano | New York Power Authority | NPCC | 1 |
| Al Adamson | New York State Reliability Council | NPCC | 2 |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☒ Yes

   ☐ No

   Comments:

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☒ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☐ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

**Scheduling Horizon** — Time frames encompassing the day-ahead period.

**Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

**Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

☐ N/A — these terms do not need to be defined for use in this standard

☐ The terms do need to be defined and I do agree with the proposed definitions

☐ The terms do need to be defined but I don't agree with the proposed definitions

Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☒ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

   ☐ No

   Comments:

8. In Requirement 2, the Transmission Service Provide**[r]** that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments:

9. Do you **[agree]** with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☐ No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☒ No

    Comments:

    R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology

    Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:

    - "Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC"

Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

☐ Yes

☒ No

Comments: Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

☐ Yes — TTC and TC are the same

☐ No — TTC and TC are not the same

Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

☐ Yes

☐ No

Comments:

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

Comments: The question is inappropriate, because the standard does not attempt to define the methodology for CBM.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

Comments: The question is inappropriate, because the standard does not attempt to define the methodology for TRM.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

    No, As the Commission noted in Order No. 890, "some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the pro forma OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs." See Order No. 890 at P158. We find that the language as proposed is broad enough to accommodate the manner in which ISOs/RTOs provide transmission service in a market-based environment and satisfies the Commissions note in Order No 890 on this subject.

    In short, so long as a TSP is following approved Market and Tariff rules that are part of a Commission-sanctioned market design, such rules should be deemed consistent with this Standard.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: The drafting team must engage in additional drafting to address the concerns raised by Order No 890.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| Individual Commenter Information<br>(Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: Michael Calimano | | |
| Organization: New York Independent System Operator | | |
| Telephone: 518-356-6129 | | |
| E-mail: mcalimano@nyiso.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☒ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☒ | 2 — RTOs, and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf

[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☒ Yes

   ☐ No

   Comments: We agree with most of the components except "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion. Also, we question the need to specify "exchanges" and "deliveries" given that purchases and sales are already included.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments: Definition is already sufficient and should not be expanded or changed.

   The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "and/or A/S" after the word "energy." The SDT should also review the definition of transmission service for consistency.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

☐ Already approved definition

Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☒ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☒ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

   ☒ No

Comments: We think those are the common used methodologies, we don't know of any others that are widely used.

However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.

Hence, we question the need for the qualifying statement – "using a Network Response Methodology" in parentheses, after "calculates AFC" in each of R4, R5 and R6.

The NYISO is concerned that the requirements identified in the standard may becoming to much of a 'how' vs. a 'what' needs to be done for reliability. The drafting team may not be able to satisfy all TSP and their associated Market Design requirements.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: We think one day is reasonable in case of TTC, TRM or CBM changes.

   If ETC changes, then re-calculation should be done within 1 or 2 hours.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☐ No

   Comments: While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (ie. Before changes, after a change, after seven days from an agreement) is confusing. Is "as agreed upon" acceptable if it is greater than every seven days?

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☒ Yes

    ☐ No

Comments: We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology.

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☒ No

Comments: Approving a request with insufficient AFC might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting a Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is insufficient. This is a common practice and should not have to be documented (justified) after the fact.

It might happen also if a re-dispatch agreement is accepted by a TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by the TP.

Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue should be addressed in the Business Practice.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☒ Yes

☒ No

Comments:

R 6 - We suggest that we require that a requester must demonstrate a reliability related need for the data. This will ensure an effort to provide the data is warranted.

R 6.3 - It is unclear what the phrase 'generation dispatch order' refers to.

R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study refused).

R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is the intension then we agree.

R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations? TP's typically exchange Net Interchange based on Schedules and sometimes reservations. However that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.

R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.

R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. The Receiving Entity could update the AFC data on an hourly basis. If the Sending Entity doesn't update the data on an hourly basis, it is not effective.

R11.2 The term "same criteria" is too general, it should be more specific.

R11.4 The term "Identify contingencies" is too general. It is unclear whether this refer to outages or the contingency elements of flow gates.

R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology

Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:

•"Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC"

Data exchanges that is required as part of the TTC calculation should be specified in the TTC Standard.

R14 Over stringent, particularly if AFCs are not calculated to the level or scope of granularity.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☒ Yes

    ☐ No

    Comments: NERC should develop some general criteria: What should be included in the TTC, TFC, ETC, TRM, CBM? How should they be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation?

    Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☒ No — TTC and TC are not the same

    Comments: This question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to an operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4 of the Comment Form. We believe TTC should be added into the FAC requirements as a defined term.

    The Reliability Standards should consider a single term for all standards.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☒ No

    Comments: TTC and TFC are reliability parameters that are determined by the transfer capability methodologies stipulated in FAC-012. These values are not determined by the TSP but by the RC or TOP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only.

The drafting team needs to work with FAC-012/013 to coordinate the determination of TTC and TFC. We believe these values are closely related and are the same on a closed interface.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for TRM

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: We are not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement, because the proposed language is broad enough to accommodate the manner in which ISOs/RTOs provide transmission service in a market-based environment. As NERC continues to develop Standards to govern reliability practices surrounding the calculation of ATC/TTC/AFC/etc... (and coordinate with NAESB regarding its development of associated business/commercial practices) in response to the Commission directive in Order No. 890, NERC's Standards must be broad enough so as not to frustrate the market-based manner in which ISOs/RTOs provide transmission service.

    As the Commission ruled in Order No. 890 with regard to, among other things, the standardization of ATC calculations, "some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the pro forma OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs."

    See Order No. 890 at P158. The proposed MOD-001 Standard appears to be in line with this direction.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information** **(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Mark Ringhausen | | |
| Organization: ODEC | | |
| Telephone: 804-290-2194 | | |
| E-mail: mringhausen@odec.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☒ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: The last catch all phrase of 'other pending potential uses of Transfer Capability' causes great concern. What does this mean? It is not clear, therefore, the definion of ETC is not clear. Should non-firm schedules be included, it is not clear from this definion, but it needs to be very clear so everyone is calulcating ETC the same way.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☒ No

   Comments: TSR is just a request for service. Definion reads that way so it is okay.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments: I prefer the new defiinion, but think we might be able to improve on it.

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☒ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments: Transmission Provider should be calculating the ATC and AFC by following details standards from NERC/NAESB on how to perform this task.

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

☒ No

Comments: These three are enough... It would be preferable to have only one for standardization across the NERC footprint.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: It needs to be a short time, but reasonable to meet for the TSP. I would say 15 minutes or less.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☐ No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☒ No

    Comments: i think we need to have a firm definion for the ATC/CBM/TRM terms before a final standard on them should be voted upon as this will impact the language in the standard.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☒ Yes

    ☐ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments:

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: Must be the same time horizon for consistency.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: Must be the same time horizon for consistency.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Chifong Thomas | | |
| Organization: Pacific Gas and Electric Co. | | |
| Telephone: 415-973-7646 | | |
| E-mail: clt7@pge.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☒ **WECC**<br>☐ **NA – Not Applicable** | ☒ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
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| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

| |
|---|
| **Group Comments (Complete this page if comments are from a group.)**<br>**Group Name:**<br>**Lead Contact:**<br>**Contact Organization:**<br>**Contact Segment:**<br>**Contact Telephone:**<br>**Contact E-mail:** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☐ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☐ Proposed definition

   ☒ Already approved definition

   Comments: The alternative definition is confusing by including contingenies with transmission elements. It seems to assume that the contingencies that should be considered for each flowgate are fixed, but in reality, the contingencies that would have the most impacts on the power flow through a flowgate changes as the system change.

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

   ☐ No

Comments: More detail on each of the methodology is needed for meaningful comment. I look forward to more information.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments:

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☐ No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☐ No

    Comments:

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

☐ Yes

☐ No

Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

☐ Yes — TTC and TC are the same

☐ No — TTC and TC are not the same

Comments: Since the TC is reliability based, if TTC is not the same as TC, then TTC should be no higher than the TC determined by the Planning Coordinator in the planning horizon and the Reliability Coordinator in the operating horizon.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

☐ Yes

☒ No

Comments: There is no reliability need to develop a TFC separate from that already developed in the FAC Standards by the Planning Coordinator in the planning horizon and the Reliability Coordinator in the operating horizon.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

Comments:

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

Comments:

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
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| E-mail: james.eckelkamp@pgnmail.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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- Load forecasts
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- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☐ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☐ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

   ☐ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

Comments:

9. Do you with the frequency of exchanging data as specified Requirement 6?

☐ Yes

☐ No

Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

☐ Yes

☐ No

Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

☐ No

Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments: Progress Energy Marketing disagree with R14, which would require Transmission Customers to provide ultimate source/sink on the Transmission Service Request. By your own definition, a Transmission Service Request is a service request by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

The ultimate source/sink requirement is incompatible with the market's trading and scheduling practices. Forward hedging is commonly transacted at Hubs, with the product defined as an "into-HUB". A supplier who delivers energy to an "into-HUB" sale cannot foresee where the buyer will ultimately sink the energy. The supplier may need to purchase transmission to the Hub's interface, but cannot know in advance what sink to input in a transmission Service Request on an upstream system.

The ultimate source/sink requirement would have an adverse impact on market development as well as market activity

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☐ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☐ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments:

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments:

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments:

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | |
|---|---|
| Name: | Brett Koelsch |
| Organization: | Progress Energy |
| Telephone: | 919 546 3046 |
| E-mail: | brett.koelsch@pgnmail.com |

| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | x | 1 — Transmission Owners |
| **X FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | x | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | x | 5 — Electric Generators |
| **X SERC** | x | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   X Yes

   ☐ No

   Comments: The language "pending potential uses" seems too vague to be included in a standard. Also, do ETCs include Transmission Service Reservations that are approved but not confirmed, or do ETCs include only confirmed TSRs ?

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   X No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   X Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   X The terms do need to be defined but I don't agree with the proposed definitions

   Comments: Differentiating between the Operating and Scheduling Horizons is unnecessary; There should only be one term for real time, current day, and next day operating periods. We would like to see "Operations" refer to real time, today, and next day. "Operations Planning Horizon" should be changed to "Near-Term Planning Horizon".

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   X Disagree

   Comments:

   The definition of ETC should include the phrase "including retail customer service" and then that parenthetical should be removed from the definition of ATC;

   Clarification is needed for the Network Response Method and Rated System Path Method to reconcile with the 1995 and 1996 documents.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   X No

   Comments: The standard should assign all requirements for developing ATC to the TSP ; AFC is just an engine. But "YES", the TSP, regardless of the engine and/or inputs it uses, should be responsible for developing its ATC methodology.

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

X Yes

☐ No

Comments: All methodologies that are used to calculate ATC should be included in this standard.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

Comments: For ATC calculations and posting of next-hour up through the next 14 days, the TSP should be given one hour to recalculate it's ATC and then it should post the new value as soon as practicable. For all longer term ATC calculations (e.g. 15 days out and further), ATC calculations and posting should have more time.

9. Do you with the frequency of exchanging data as specified Requirement 6?

☐ Yes

X No

Comments: The intent of R6 is unclear. It is unclear whether data exchange is for forward looking or historical time periods. The requirement for beginning data exchange within 7 days is ambitious. A realistic time frame would be 90 days if it is forward looking.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

☐ Yes

☐ No

Comments: One methodology should be used for the TSP's system. Change "its sole" to "a single" or to "one". Also, the standard should have only one requirement that defines the when and where of ATC methodology ; If you want the same process to be applied across the TSP's whole system and across all time horizons then say that plainly in one requirement instead of splitting the where and when between R9 and R11.

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    X No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    X No

    Comments: R3 – What is the intent of this requirement? If the intent is to provide data within 7 days of the request then the requirement needs to be reworded.

    R8 – R14 should apply to “ATC” not “ATC and AFC” because AFC is just an ATC engine, and these requirements should be moved to the beginning of the standard, followed by the engine-specific calculation requirements.

    R11.2 – “internal expansion plan” does not apply within 13 month horizon. Should instead be “internal near-term planning”

    R11.5 – reject inclusion of “use the same power flow model” as this is impossible to apply. Many ATC models use NERC MMWG models as their basis. In planning studies, additional lower voltage detail is included.

Also, the standard should have only one requirement that defines the when and where of ATC methodology ; If you want the same process to be applied across the whole system and across time horizons then say that plainly in one requirement instead of splitting the where and when between R9 and R11.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    X No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don’t believe these are the same, please explain what you feel are the differences between TC and TTC.

    Yes — TTC and TC are the same

No — TTC and TC are not the same

Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

X Yes

☐ No

Comments: **<u>All</u>** of the calculations related to ATC should be addressed in the same standard. PE suggests that all requirements be included in MOD-001.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

Comments:

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

Comments:

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

Comments: PE suggests renaming the Standard "ATC Calculation Methodologies" and restate Purpose. AFC is just one engine type used to calculate ATC.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

| | |
|---|---|
| **Group Name:** | SCE&G |
| **Lead Contact:** | **Al McMeekin** |
| **Contact Organization:** | **South Carolina Electric & Gas** |
| **Contact Segment:** | **1 - Transmission Owner** |
| **Contact Telephone:** | **803.217.7529** |
| **Contact E-mail:** | **amcmeekin@scana.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Clay Young | SCE&G | SERC | 1 |
| Stan Shealy | SCE&G | SERC | 1 |
| Gene Delk | SCE&G | SERC | 1 |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
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Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
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**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

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   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: The ETC definition reference to "Native Load uses" is not applicable to ATC calculations. By definition, a transfer analysis determines the amount of import (or export) capacity possible in addition to the native load service modeled in the base case. Internal transfers to serve network loads are not included in TTC values and should not be subtracted from TTC to obtain ATC. Conversely, since TFC is similar to a facility rating, not a (n-1) transfer analysis , the impacts of serving native load must be considered in calculating AFC and are therefore appropriate in an AFC calculation.

   Either the ETC definition should be changed to reflect the differences between ATC and AFC calculations or the ATC formula should be changed to remove ETC from the calculation. This could be accomplished by using the following ATC calculations.

   Firm ATC = TTC - CBM - TRM - Firm Interface Commitments Non-firm ATC = TTC - All Interface Commitments + Postbacks of Unscheduled Service

   In addition, the ETC definition should be modified to remove references to Contingency Reserves, which are not an Existing Transmission Commitment. The ATC equations allow for uncertainties such as CBM and TRM. To the extent additional reserve margins are required, they should accounted for as such in the AFC or ATC equations, not by lumping them into ETC. Also, references to pending uses should be removed. ETC should include only commitments, not potential uses. A suggested ETC definition is provided below.

   ETC: Used in the context of calculating AFC, ETC reflects the impacts of power flows associated with serving native loads, commitments for firm and non-firm transmission service, and any other commitments for transmission service not covered by OATT requirements.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

Should this definition be expanded or changed?

☐ Yes

☒ No

Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments: Clarification is needed for the Network Response Method and Rated System Path Method to reconcile with the 1995 and 1996 documents. As example, R1 is confusing using the definitions as stated in current draft. NRM has been applied to two separate calculations (FCITC and AFC). In R1, add "not used for AFC" following "Network Response Methodology" in the parenthetical.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed

changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☐ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

Comments:

9. Do you with the frequency of exchanging data as specified Requirement 6?

☐ Yes

☒ No

Comments: It is unclear whether data exchange is for forward looking or historical time periods. The requirement for beginning data exchange within 7 days is ambitious. A realistic time frame would be 90 days if it is forward-looking.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

☐ Yes

☐ No

Comments: Change "its sole" to "a single" or to "one." The statement in the question above is clear - the language of the requirement was not as clearly stated.

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

☐ No

Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments: R3 - The requirement is not clear on timeframes. Is it talking about the current ATC values or values into the future? If so, how far into the future. What is intent? If the intent is to create the obligation to provide current data within 7 days of the request, then the requirement needs to be reworded.

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    ☐ Yes

    ☒ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

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    ☐ No — TTC and TC are not the same

    Comments: However, there are different definitions for TTC and TC. The definitions should be the same thus the current definition needs to be clarified.

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    ☒ Yes

    ☐ No

    Comments: All of the calculations related to ATC (TFC, TTC, AFC) should be addressed in the same standard. Suggest that all requirements be included in MOD-001 and that FAC-012 and FAC-103 should be retired.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments:

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments:

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Comments: Some TSP's OATT have requirements that components of ATC be provided by third parties. For example, in one case, a TSP is required to use the AFC calculations provided by the Reliability Coordinator in determining its ATC.

19. Do you have other comments that you haven't already provided above on the proposed standard?

Comments: Suggest renaming standard to ATC Calculation Methodologies and restate Purpose. AFC is just one of the engines used to calculate ATC.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

| | |
|---|---|
| **Group Comments (Complete this page if comments are from a group.)** | |
| **Group Name:** | SERC Available Transfer Capability Working Group (ATCWG) |
| **Lead Contact:** | **Ken Keels** |
| **Contact Organization:** | **SERC Reliability Corporation** |
| **Contact Segment:** | **10 - RRO** |
| **Contact Telephone:** | **704-948-0761** |
| **Contact E-mail:** | **kkeels@serc1.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Darrell Pace | Alabama Electric Cooperative, Inc. | SERC | 10 |
| Helen Stines | Alcoa Power Generating, Inc. | | |
| Marion Lucas | Alcoa Power Generating, Inc. | | |
| Eugene Warnecke | Ameren | | |
| Kiet Nguyen | Associated Electric Cooperative, Inc. | | |
| Zack Stica | Associated Electric Cooperative, Inc. | | |
| Chris Bradley | Big Rivers Electric Corporation | | |
| Bob Crosier | E.ON U.S. Services Inc. | | |
| Joachim Francois | Entergy | | |
| Robin Wiley | Georgia Transmission Corporation | | |
| Ross Kovacs | Georgia Transmission Corporation | | |
| Renuka Chatterjee | Midwest ISO | | |
| Larry Middleton | Midwest ISO | | |
| Jerry Tang | Municipal Electric Authority of Georgia | | |
| Donald Williams | PJM Interconnection, LLC | | |
| Phil Creech | Progress Energy Carolinas | | |
| John Troha | SERC Reliability Corporation | | |
| Ken Keels | SERC Reliability Corporation | | |
| Gene Delk | South Carolina Electric & Gas Company | | |
| Al McMeekin | South Carolina Electric & Gas Company | | |
| Stan Shealy | South Carolina Electric & Gas Company | | |
| Chad Cooper | South Carolina Public Service Authority | | |
| Derelyn Smith | Southeastern Power Administration | | |
| Carter Edge | Southeastern Power Administration | | |
| DuShaune Carter | Southern Company Services, Inc. - Trans | | |
| Bryan Hill | Southern Company Services, Inc. - Trans | | |
| Jonathan Hayes | Southwest Power Pool, Inc. – ITO | | |
| Doug Bailey | Tennessee Valley Authority | | |

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
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- Path definitions and facility ratings
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Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

---

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments: The ETC definition reference to "Native Load uses" is not applicable to ATC calculations. By definition, a transfer analysis determines the amount of import (or export) capacity possible in addition to the native load service modeled in the base case. Internal transfers to serve network loads are not included in TTC values and should not be subtracted from TTC to obtain ATC. Conversely, since TFC is similar to a facility rating, not a (n-1) transfer analysis , the impacts of serving native load must be considered in calculating AFC and are therefore appropriate in an AFC calculation.

   Either the ETC definition should be changed to reflect the differences between ATC and AFC calculations or the ATC formula should be changed to remove ETC from the calculation. This could be accomplished by using the following ATC calculations.

   Firm ATC = TTC - CBM - TRM - Firm Interface Commitments Non-firm ATC = TTC - All Interface Commitments + Postbacks of Unscheduled Service

   In addition, the ETC definition should be modified to remove references to Contingency Reserves, which are not an Existing Transmission Commitment. The ATC equations allow for uncertainties such as CBM and TRM. To the extent additional reserve margins are required, they should accounted for as such in the AFC or ATC equations, not by lumping them into ETC. Also, references to pending uses should be removed. ETC should include only commitments, not potential uses. A suggested ETC definition is provided below.

   ETC: Used in the context of calculating AFC, ETC reflects the impacts of power flows associated with serving native loads, commitments for firm and non-firm transmission service, and any other commitments for transmission service not covered by OATT requirements.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

Should this definition be expanded or changed?

☐ Yes

☒ No

Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments: Clarification is needed for the Network Response Method and Rated System Path Method to reconcile with the 1995 and 1996 documents. As example, R1 is confusing using the definitions as stated in current draft. NRM has been applied to two separate calculations (FCITC and AFC). In R1, add "not used for AFC" following "Network Response Methodology" in the parenthetical.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed

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|---|---|---|
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| Organization: | | |
| Telephone: | | |
| E-mail: | | |
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| Group Comments (Complete this page if comments are from a group.) | | | |
|---|---|---|---|
| **Group Name:** | Southern Company | | |
| **Lead Contact:** | **J. T. Wood** | | |
| **Contact Organization:** | **Southern Company Services** | | |
| **Contact Segment:** | | | |
| **Contact Telephone:** | **205-257-6238** | | |
| **Contact E-mail:** | **jtwood@southernco.com** | | |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Marc Butts | Southern Company Services | SERC | 1 |
| Roman Carter | Southern Company Services | SERC | 1 |
| Jim Busbin | Southern Company Services | SERC | 1 |
| John Lucas | Southern Company Services | SERC | 1 |
| Keith Calhoun | Southern Company Services | SERC | 1 |
| Dushaune Carter | Southern Company Services | SERC | 1 |
| Steve Corbin | Southern Company Services | SERC | 1 |
| Ron Carlsen | Southern Company Services | SERC | 1 |
| Doug McLaughlin | Southern Company Services | SERC | 1 |
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   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

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2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

Comments: Is the service definition to include point-to-point and network. Suggested TSR definition is provided below:

TSR: The act of making a request for reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) or Receipt to the Point(s) of Delivery under Part II or III of the Tariff.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments: Make sure that the correlation to other standards is correct when making this change

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☒ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: Scheduling and Operating definitions need to be swapped. These are defined in Order 890 paragraph 323.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments: Define network response and rated system path method more implicit (wording and intent) to the methods of ATC and AFC. Look more to the explanations in the 96 documents (pp15). The present definitions for Network Response Method and Rated System Path Method are unclear and do not adequately describe the three methods in the standard. Throughout the document, the three methods are Rated System Path Method, Network Response ATC Method and Network Response AFC Method. The two terms were taken from the 1996 document. Network Response Method that is described in that document appears to reflect the AFC process. A suggestion would be to used the Network Response Method for the AFC process and the Area Interchange Method (1995 document) for the ATC process..

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response

— ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments: As discussed in ETC definition, ETC as currently defined is not applicable to the ATC calculation. Also, ATC should be expanded into separate firm and non-firm ATC calculations. ETC should be replaced by firm and non-firm interface usage. Internal native load serving uses are not a component of ATC. Non-firm ATC should reflect that CBM (and often TRM) are not deducted and also should reflect the postback of unscheduled service. Some discussion of adjustments for redirected service in interface usage amounts should be included. Indication of whether TTC values reflect simultaneous or non-simultaneous values should also be included. AFC should be expanded into separate firm and non-firm AFC calculations. Non-firm AFC should reflect that CBM (and often TRM) are not deducted and also should reflect the postback of unscheduled service. The formula seems to indicate TRM and CBM are MW values. Some TPs address TRM by derating TFC values by a percentage, such as 5%. Some discussion of this practice or alternate formulas for AFC for those utilizing this practice should be included. The alternate approach should include discussion of how TFC values are affected for both firm and non-firm AFC. The formula does not include how counterflows are treated. Since TFC is similar to a facility rating, not a (n-1) transfer analysis, the impacts of counterflows must be considered in calculating AFC and are therefore appropriate in an AFC calculation. Similarly, some discussion should be included of how inadvertent flows from neighboring areas (loop flows) are considered. An additional formula should be modified will be required to include the calculation of ATC from AFC. Some discussion of what rating is used for TFC (static, Rate A, Rate B, ambient adjusted, etc.) is used in which horizons should be included.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: We agree with this requirement for ATC. We do not agree that TTC should be recalculated whenever a parameter changes.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☒ No

   Comments: The posting and reposting of data in the OASIS system needs to be taken out of this standard and requirements be put into NAESB standards. Most of this we already do. G&T outages on SDX, dispatch order would be new, power flow model on request, load forecast will be posted on OASIS, Flowgates OK, TFC-our ratings are provided in our cases today, ETC=TSRs is on OASIS] Question: Is R6 dictating duplication of already available information in a different format?

Also, does 6.8 require 168 models to be created each hour, or just changes in 168 hours of AFC values based upon changes in transmission service requests? Same question for daily. The document refers to OASIS several times. Why specify update intervals here rather than simply referring to FERC OASIS requirements or NAESB business practices? This sets up possible conflict. There is no reliability driver for these particular update frequencies.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

☐ Yes

☐ No

Comments: One methodology is sufficient. For ATC, although there mat be situations where multiple approaches are appropriate to address radial vs. interdependent portions of a system. Also, flexibility may be required in calculating TTC. For example posting non-simultaneous values on radial interfaces and simultaneous values on interdependent paths.

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

☒ No

Comments: This was put in here to cover the AFC's AFTFC (?). If this requirement stays in the standard, a suggested rewording is needed. A value "less than" automatically implies a value "other than." The requirement states, "If the TSP approves a TSR...." What if the TSP denies a TSR? This reads like a policy, not a reliability requirement. TSPs already have requirements under the OATT to provide justifications from approving/denying service.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments: R1 and R4 for calculations both firm and non-firm. All references to TTC and TFC need to be move off to FAC 12 and 13. R11.2 phrase "internal expansion planning" be removed. R11.2-11.5 is referencing to TTC and TFC/AFC calculations should be moved to FAC 12-13. R7 what updated information should be coordinated and for what purpose? Is this not a posting issue? The posting and reposting of data in the OASIS system needs to be taken out of this standard and requirements be put into NAESB. R14 the ultimate source and sink hold for

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☒ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☒ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments: the TFC methodology should be developed in the FAC12-13 standard and not in MOD-001

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: addressed in CBM standard. In general, CBM is applicable to each time horizon in the context of calculating firm import ATC.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: addressed in TRM standard. In general, TRM is applicable to each time horizon in the context of calculating firm import ATC. Discussion is needed to determine whether TRM should be included in determing non-firm ATC and in export ATC calculations.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: The drafting team should consider whether particular directives in Order 890 adversely impact reliability and respond appropriately.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: R5.1 and R5.2 only cover the aspects of non-firm with dealing with an entity's counter flow rules. This could be resolved by adding equations that outline the firm and non-firm aspects of AFC. Firm and non-firm also differ in the treatment of TRM/CBM and postbacks of unscheduled service.

    R8 If Firm and Non-firm equations are used for ATC/AFC this requirement would not be necessary.

    R11.2: There is no "internal expansion planning" during these time frames. The phrase should be deleted. It is unclear what is meant by "use the same criteria and assumptions used to conduct reliability assessments and internal expansion planning for different time frames"

    Generally, expansion planning considers an N-2 approach as opposed to an N-1 in the operating horizon. Expansion planning also generally considers more robust dispatch assumptions in the local area under review. Also, although transfer analysis is a consideration in expansion planning, generally expansion plans are driven by local load serving constraints (thermal or voltage), not ATC considerations (limits to transfers). It would be inappropriate to utilize the same assumptions for ATC as expansion planning.

    R11.3: R11.2 states that the same criteria should be used and R11.3 states that the rationale for any differences should be documented. Does this allow of differences in R11.2?

    R11.4: This is not a big deal, but contingencies would be considered in the TTC and not the ATC. It is unclear what is meant by "Identify the contingencies considered in ATC". Is this a general statement of N-1 or specific contingencies used in the TTC assessment?

    R11.5: This is a planning issue, but this requirement could be problematic and difficult to comply with, especially using the same power flow models. The intent was to make sure that the requirements that you use to grant service were no more stringent that those used to plan for system expansion. We might want to consider suggesting a rewording. Generic ATC values calculated beyond 13 months are not used for addressing TSRs. I am not aware of yearly transmission service being evaluated absent a TSR study of the specific transfers, which would be performed under the planning process, so the models would be one in the same. I assume the "for the same timeframe" language indicates that the assumptions for beyond 13 months do not need to match the assumptions within the 13 monthly timeframe. In addition to the differences in expansion planning discussed above, planning models generally include firm commitments for long term service which may be inappropriate to use in operations (such as CT plant modeled on in April).

    R14 Under the OATT, transmission customers are not required to buy full path transmission service. This would also seem to significantly complicate the redirecting of service, another customer right offered under the OATT.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Bert Bressers | | |
| Organization: South West Power Pool | | |
| Telephone: 501-614-3300 | | |
| E-mail: bbressers@spp.org | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☒ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☒ | 2 — RTOs, and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

| | |
|---|---|
| **Group Comments (Complete this page if comments are from a group.)** | |
| **Group Name:** | SouthWest Power Pool |
| **Lead Contact:** | **Bert Bressers** |
| **Contact Organization:** | **SouthWest PowerPool** |
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| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

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[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☒ Yes

   ☐ No

   Comments:

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☒ Yes

   ☐ No

   Comments: Definition should include reference to Source, Sink .

   Add to end of proposed definition …… and from ultimate Source to ultimate Sink.

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☒ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: We think terms need to be defined however they should be more general to allow for regional differences.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☒ Agree

   ☐ Disagree

   Comments: Remaining definitions: AFC, Network Response Method, Rated System Path Method, TFC, Transmission Reservation are OK

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☒ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments: We think those are the common used methodologies, we don't know of any others

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments: We think one day is reasonable in case TTC, TRM or CBM changes.

   If ETC changes re-calculation should be done within 1 of 2 hours.

   TTC typically only changes with upgrade of the flow gate element. TRM values change when the TP re-calculates the TRM values, twice a year or something like that. So TTC and TRM don't change on a daily basis, more on a Seasonal Basis. It can take SAS 70 related Change Control Approvals to get the values changed in the AFC databases. Getting approvals can take an hour or more if it is defined as an Emergency Change. After adding the new values to the AFC databases, it can take an hour or more before all Horizons are updated in Oasis Automation. The EMS AFC Calculator has to re-run all hours and days of the Horizons and that takes a little more than an hour. So starting from the time a new TRM or TTC value is submitted to TP, it can take a few hours before it is in Oasis and Oasis Automation. Also in many cases the Transmission owner doesn't immediately inform the TP of an upgrade the minute it happens, most of time a few days later. So it is in general not considered critical to immediately update the ATC and AFC values when TTC or TRM changes.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☒ Yes

   ☐ No

   Comments: The requirement's are very general and don't specify data exchange before changes, after a change, after seven days from an agreement. It is not clear if "as agreed upon" is acceptable if it is greater than every seven days.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☒ Yes

    ☐ No

Comments: We convert AFC to ATC numbers on OASIS, however we start off from AFC numbers that are calculated using one and same methodology

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

☒ No

Comments: It might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is un-sufficient. This is a common practice and should not have to be documented (justified) after fact.

It might happen also if a re-dispatch agreement is accepted by TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by TP.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments:

R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study refused).

R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is intension we are OK.

R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations. TP's typically exchange Net Interchange based on Schedules and sometimes Reservations , however that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.

R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.

R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. We (receiving Entity) update the AFC data on an hourly basis however if the Sending Entity doesn't update the data on an hourly basis, it is not effective.

R11.2 "same criteria" is to general, should be more specific

R11.4 "Identify contingencies" is to general. Does this refer to outages or the contingency elements of flow gates.

R14 Over stringent, particular if AFC aren't calculated to the level or scope of granularity.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☒ Yes

    ☐ No

    Comments: We recommend developing some general criteria, what should be included in the TTC, TFC, ETC, TRM, CBM, and how they should be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☐ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments: That question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they had same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to a operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4. of the Comment Form. It looks like FAC-012-1 is more related to Reliability function (real time /semi real time) and MOD-001-1 is more related to Tariff function

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments: It looks like FAC-012-1 is more related to Reliability function and MOD-001-1 is more related to Tariff function. FAC-012 should probably describe how the Normal Rating and Emergency Rating should be calculated, using what weather conditions and what safety margin for equipment. MOD-001-1 could refer to those definitions and indicate (as an example) that Normal Rating could be used for single element PTDF flow gates and Emergency Rating for OTDF flow gates

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments: We don't use CBM, so we don't really have an opinion

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments: TP should calculate the TRM value. TRM should be a seasonal (or yearly value), based on the largest available resources (not scheduled to have maintenance) in that season. If it is a yearly value it should be based on the largest unit. We don't think TRM should be a Monthly value, because maintenance of Resources can change and you might sell service on a lower TRM based on scheduled maintenance of the largest unit. If the scheduled maintenance changes and largest unit moves back in that Month you could potential have oversold system. To play it safe TRM should be seasonal or yearly value. A TP could decide based on a current outage of the unit which was the basis for current TRM value, to lower TRM for the time frame of the outage however we don't think that this type of detail should be incorporated or described in the MOD-001-1.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: No, we are not aware of any. Some TP's may find the need to include more detail into MOD-001-1 to address the concerns raised in the FERC Order No. 890.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments: None.

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information** | | |
|---|---|---|
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☒ ERCOT | ☐ | 1 — Transmission Owners |
| ☐ FRCC | ☐ | 2 — RTOs, and ISOs |
| ☒ MRO | ☐ | 3 — Load-serving Entities |
| ☐ NPCC | ☐ | 4 — Transmission-dependent Utilities |
| ☒ RFC | ☐ | 5 — Electric Generators |
| ☒ SERC | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☒ SPP | ☐ | 7 — Large Electricity End Users |
| ☐ WECC | ☐ | 8 — Small Electricity End Users |
| ☐ NA – Not Applicable | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

   Should this definition be expanded or changed?

   ☐ Yes

   ☐ No

   Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☐ Proposed definition

   ☐ Already approved definition

   Comments:

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☐ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments:

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☐ Disagree

   Comments:

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

   ☐ Yes

   ☐ No

   Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

   ☐ Yes

   ☐ No

Comments:

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments:

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☐ No

   Comments:

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

    ☐ No

    Comments:

11. Do you think that Requirement 13 in this proposed standard necessary?

    ☐ Yes

    ☐ No

    Comments:

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

    ☐ Yes

    ☒ No

    Comments: We disagree with R14 which requires the Transmission Service Provider to require Transmission Customers to provide ultimate source and sink on Transmission Service Requests and Transmission Customers must use the same source and sink on Interchange Transaction Tags. The main reasons we disagree with this requirement are that it is incompatible with current market trading and scheduling practices and is not always relevant.

    When a Transmission Customer reserves transmission for use in a trading hub transaction (e.g., "into Entergy", "into Southern"), it is not always possible for the Transmission Customer to know what the actual source or sink will be at the time of making the reservation.

When the source or sink is within a pool, it is not possible to identify the actual generating source or ultimate sink.

When transactions cross a DC tie, it would not be necessary for reliability or calculating ATC to identify the true source or sink on the opposite side of the DC Tie.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

    ☐ Yes

    ☐ No

    Comments:

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

    ☐ Yes — TTC and TC are the same

    ☐ No — TTC and TC are not the same

    Comments:

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

    ☐ Yes

    ☐ No

    Comments:

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

    Comments:

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments:

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments:

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

Please use this form to submit comments on the first draft of the ATC/AFC Methodology Documentation Standard (MOD-001-1 ATC and AFC Calculation Methodologies). Comments must be submitted by **March 16, 2007**. You must submit the completed form by email to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

| **Individual Commenter Information** **(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: W. Shannon Black et al | | |
| Organization: Behalf of the WECC MIC MIS ATC Task Force | | |
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| E-mail: sblack@smud.org / W. Shannon Black | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations, and Regional Entities |

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|---|---|---|---|
| **Group Comments (Complete this page if comments are from a group.)** | | | |
| **Group Name:** | WECC MIC MIS ATC Task Force | | |
| **Lead Contact:** | **W. Shannon Black** | | |
| **Contact Organization:** | **Sacramento Municipal Utility District** | | |
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| **Bob Schwermann** | **SMUD** | **WECC** | |
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| **Dave Lunceford** | **CAISO** | **WECC** | |
| **Jerry Smith** | **APS** | **WECC** | |
| **Lou Ann Westerfield** | **IPUC** | **WECC** | |
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| **Sueyen McMahon** | **LADWP** | **WECC** | |
| **Terri Kuehneman** | **SRP** | **WECC** | |
| **Tadd Simms** | **SMUD** | **WECC** | |
| * Although others have participated in the WECC MIC MIS ATC Task Force, these are predominate personnel contributing. | | | |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

## Background Information

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may (in the future) reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[1].

A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[2]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 13 and 14). The comment form includes a question asking whether the values for TC and TTC should be considered the same value.

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that the industry will know how these precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards dealing with those values.

The Standard Drafting Team would like to receive industry comment on the proposed requirements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements.

[1] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
[2] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

**You do not have to answer all questions.**
*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability.

   Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☒ No

   Comments:

   Although the definition is sufficient to "describe" Existing Transmission Commitments, it is not sufficient to "calculate the ETC." ETC is an essential variable in the ATC calculation on par with TTC, CBM and TRM. As such, ETC should be addressed in its own freestanding standard to be consistent with the other ATC variables and to further promote clarity, consistency and transparency of this essential ATC component. This group does not concur that ETC should be addressed as a subcomponent of MOD-01 as stipulated in P243 of Order 890.

   To bring the definition in line with Order 890, P. 244, this Team suggests:

   1) The following language should be used as the definition for Existing Transmission Commitments.
   2) To bring the definition into accord with Order 890, the Team suggests striking any reference to Contingency Reserves from the definition.

Existing Transmission Commitments (ETC):

Any combination of:

1) Native Load commitments (including network service),
2) Load forecast error
3) Losses
4) Existing commitments for energy purchases, exchanges, deliveries, or sales and existing commitments for transmission service,
5) Appropriate point-to-point reservations
6) Rollover rights associated with long-term service
7) Other pending potential uses of transfer capability, either TTC or AFC, identified through the NERC process.

2. This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

Should this definition be expanded or changed?

☐ Yes

☒ No

Comments:

3. This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the Flowgate caused by power transfers.

   This is the definition of Flowgate in the NERC *Glossary of Terms Used in Reliability Standards:* A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

   Which definition do you prefer?

   ☒ Proposed definition

   ☐ Already approved definition

   Comments: The proposed definition is more descriptive than the definition in the NERC glossary.

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

   **Operating Horizon** — Time frames encompassing same-day and real-time periods.

   **Scheduling Horizon** — Time frames encompassing the day-ahead period.

   **Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months

   **Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

   Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

   ☐ N/A — these terms do not need to be defined for use in this standard

   ☒ The terms do need to be defined and I do agree with the proposed definitions

   ☐ The terms do need to be defined but I don't agree with the proposed definitions

   Comments: These definitions do not agree with the definitions identified in Order 890 (see P323) as follows:

   Operating Horizon – day ahead and pre-schedule

   Scheduling Horizon – same day and real-time

   Planning Horizon – beyond the operating horizon

   The fact that FERC and NERC do not agree on the definition of these terms confirms the need to formalize the definition.

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Agree

   ☒ Disagree

   Comments:

   The Network Response Method definition needs clarity and a stronger description.

   The NERC Team indicates in Q7 that there is a difference between the Network Response Methodology-ATC and Network Response Methodology-AFC that is not yet apparent. If this is correct, a separate free standing definition would be warranted for each of the methodologies.

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

☒ Yes

☐ No

Comments:

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies).

   Should the drafting team consider other methodologies?

(Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

☐ Yes

☒ No

Comments:

For purposes of MOD-01, the WECC Team does not believe the standing NERC / NAESB ATC Drafting Team should entertain any additional methodologies. Preclusion at this stage does not foreclose the future use of the NERC SAR process should a more efficacious approach arise from within the industry.

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

   Comments:

   The WECC Team concurs that ATC should be recalculated anytime there is a change to any of the ATC variables. However, once the ATC is recalculated, the periodicity of posting the ATC is a business practice that should be deferred to NAESB.

9. Do you with the frequency of exchanging data as specified Requirement 6?

   ☐ Yes

   ☐ No

   Comments: The question is specific to entities using the AFC methodology and should be reserved for comment by those entities.

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

    ☐ Yes

☐ No

Comments:

This requirement is unnecessary and should be deleted. If the NERC team will not delete the Requirement, at minimum the word "sole" must be deleted from the Requirement.

If, for example, a TSP has operational needs that dictate the use of the AFC Methodology for paths within its network and the Rated System Path for interfaces with its neighbors, either of these methodologies is allowed under MOD-01. So long as the TSP consistently and transparently applies any of the NERC approved methodologies to it facilities and communicates that application to all appropriate entities, this approach should be allowed as it has met FERC's core purposes without disrupting operations.

In contrast, this constrictive approach over reaches the FERC mandate of consistency and transparency, increases the potential for seams between interchanges and otherwise imposes a burden to alter operations where no remedy is needed.

In support of the WECC Team's position:

FERC found in Order 890 that "the potential for undue discrimination stems from two main sources: (1) variability in the calculation of the components that are used to determine ATC and (2) the lack of a detailed description of the ATC calculation methodology and the underlying assumptions used by the transmission provider." P. 209. Neither of these concerns is at issue should a TSP use more than one NERC authorized methodology.

Further, FERC found that so long as "all of the ATC components and certain data inputs and assumptions are consistent, the three ATC calculation methodologies being finalized by NERC through the reliability standards development process will produce predictable and sufficiently accurate, consistent, equivalent, and replicable results. It is therefore not necessary to require a single industry-wide ATC calculation methodology. ***The Commission instead concludes that use of the ATC calculation methodologies included in reliability standards currently being developed by NERC is acceptable."*** P. 210.

11. Do you think that Requirement 13 in this proposed standard necessary?

☐ Yes

☐ No

Comments:

The WECC Team would like an example as to why the NERC Team believes this Requirement is necessary.

The WECC Team believes that if ATC is posted on OASIS, the entire posted amount must be made available for purchase. For example, if an entity requests 100 MW of legitimately posted ATC and the TSP refuses the 100 MW request but grants 80 MW instead, that TSP must provide to the requesting entity a full and written explanation of why the full 100 MWs of posted ATC were not made available.

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

☐ Yes

☒ No

Comments: See our comments and answer to Question 19.

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

☐ Yes

☒ No

Comments: As clarity is essential for each ATC variable, the WECC Team suggests that any further prescription or standardization is addressed in a free standing standard specifically addressing each variable of the ATC calculation. For example, a free standing standard should be initiated for ETC.

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

☒ Yes — TTC and TC are the same

☐ No — TTC and TC are not the same

Comments: Additionally, the NERC Drafting Team should decide which of the NERC Glossary terms best describes this specific capacity and eliminate the other.

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer.

☐ Yes

☒ No

Comments: TFC methodology should be addressed in the same standard as is TTC methodology. This is the logical parallelism to addressing AFC and ATC in the same standard.

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain.

Comments:

This question is best deferred to the CBM standard.

That said, the LSE should be the entity that determines CBM and should also be allowed the authority to call on the CBM when appropriate.

In keeping with Order 890, P. 358 and also MOD-05 as currently implemented, the WECC Team suggests that CBM be recalculated no less than annually with allowance to recalculate more frequently as circumstances change.

To the extent CBM is not scheduled (remains "unused") CBM must be posted on OASIS on a non-firm basis. Order 890, P. 354.

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

    Comments:

    This question is best deferred to the TRM standard.

    That said, the Transmission Service Provider in conjunction with its Transmission Planner should determine the TRM.

    How often TRM should be calculated is dependent upon what elements go into the TRM as will be dictated in the TRM standard. If load forecast error becomes part of TRM, the TRM should be adjusted hourly. By contrast, if the TRM is solely to address seasonal changes that an annual then on/off peak recalculation may be in order.

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    Comments: No.

19. Do you have other comments that you haven't already provided above on the proposed standard?

    Comments:

    Yes. The drafting team should be encouraged to include in the MOD-01 a formula describing how AFC is converted into ATC for the subsequent posting of ATC by those entities utilizing AFC.

    "The Commission also required each transmission provider using an Available Flowgate Capacity (AFC) methodology to explain its definition of AFC, its calculation methodology and assumptions, and its process for converting AFC into ATC." P. 189.

R3. This requirement states that the TSP "…shall, when requested, provide or make available, the following values…" What is the retention period for the TSP such that the data will still be available when requested? The drafting team should modify this requirement such that the TSP is only required to respond to requests for data that are within the time frames established within their filed Tariff. For example, TSP's should not have to provide ATC values that would require a System Impact Study.

R3. & R6. This requirement states that the TSP provide certain data when requested and when the requestor "…has a reliability related need for the values." How does the TSP judge whether the requester has a reliability related need or not? The drafting team needs to establish a criterion for the need or strike this phrase from the requirement.

R11.2 & R11.3 This requirement states that TSP's, "Require that the calculation of ATC or AFC use the same criteria and assumptions used to conduct reliability assessment and internal expansion planning for different time frames etc." and that they "Document the criteria used for calculating ATC or AFC values for the different time frames etc. and the rationale for any differences between these."

Those TSPs who use the Rated System Path Methodology rely heavily on criteria and assumptions for calculating the TTC for a path but not for the calculation of ATC. Once the TTC for a path is determined the determination of ATC is simple math with little concern for criteria or assumptions.

We recommend that the drafting team restrict these two requirements to those TSP's who use the AFC Calculation Methodology and create a parallel requirement for the calculation of TTC for those TSP's who use the Rated System Path Methodology.

R11.4 & R11.5 This requirement states that TSP's must "Identify the contingencies considered in the ATC and AFC calculation methodologies." and that they "..use the same power flow models, and the same assumptions regarding load, generation dispatch, special protection systems etc. as those used in the expansion planning for the same time frames." This would be important for those who use the AFC Calculation Methodology and build power flow models to determine if capacity will be available. For those using the Rated System Path Methodology these factors are important for the determination of TTC but not for the determination of ATC. Rated System Path Methodology users do not build power flow cases and study contingencies to determine "ATC"; rather, these case studies are done to determine the TTC rating of paths. Therefore we recommend that the drafting team restrict these two requirements to those TSP's who use the AFC Calculation Methodology and create a parallel requirement for the calculation of TTC for those TSP's who use the Rated System Path Methodology.

R12. This requirement states that TSP's must "Identify the Transmission Service Providers with which the data used in the calculation of ATC or AFC is exchanged." Coordination of data is important but for those using the Rated System Path Methodology this coordination takes place when the TTC for the path and not the ATC for the path is calculated. We recommend that the drafting team make this requirement apply only to those using the AFC Methodology in MOD 001 and create a comparable requirement in the TTC calculation standard for those using the Rated System Path Methodology.

R14. This requirement states that "The Transmission Service Provider shall require that the Transmission Customer provide both ultimate source and ultimate sink on the Transmission Service Request and shall require that the Transmission Customer use the same source and sink on Interchange Transaction Tags."

The WECC Team suggests this Requirement should be applicable only to entities using the AFC methodology.

For entities using the Rated System Path (re: the majority of WECC) the source and sink are already part of the Tagging system. At minimum that makes the Requirement redundant for the Rated System Path participants. Further, since Tagging is a business practice, this requirement would fall into the purview of NEASB. Lastly, unlike those using the AFC methodology, the source and sink of each request and subsequent schedule is not needed to determine ATC as it is for those determining AFC using Flowgates. Since entities calculating AFC need to know the source and sink for Flowgate modeling purposes (whereas those using the Rated System Path method do not), the logical application for this Requirement is to those using the AFC methodology.

The ATC Standard Drafting Team thanks all commenters who submitted comments on Draft 1 of the Available Transfer Capability (ATC) Standard (MOD-001). The standard was posted for a 30-day public comment period from February 15 through March 16, 2007. The drafting team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 35 sets of comments, including comments from more than 91 different people from more than 52 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Since the drafting team posted its first draft of MOD-001, FERC issued Order 890 and Order 693 – with very specific directives relative to ATC. The drafting team made significant changes to the first draft of MOD-001 in response to stakeholder comments and in response to the FERC Orders.

The changes to MOD-001 resulting from stakeholder comments and FERC directives were so extensive that the revised standard bears very little resemblance to the first draft of MOD-001.

- There was no consensus on several of the proposed definitions, and those that were not supported by stakeholders have either been removed or revised.

- The drafting team added much more detail to each of the methods of determining ATC and its related components and subdivided the requirements into a greater number of standards as follow:

  - MOD-001 - This is now an "umbrella" standard and contains the 'generic' requirements applicable to all methods of determining ATC. All of the equations have been removed from this standard.
  - MOD-028 – This standard addresses requirements unique to the Network Response method of determining ATC.
  - MOD-029 – This standard addresses requirements unique to the Rated System Path method of determining ATC.
  - MOD-030 – This standard addresses requirements unique to the Flowgate Network Response method of determining ATC, including requirements to convert AFC to ATC
  - MOD-004 – This standard addresses requirements for Capacity Benefit Margin (CBM)
  - MOD-008 – This standard addresses requirements for Transmission Reliability Margin (TRM).

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at

609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | John Bussman | AECI | ✓ | | | | ✓ | ✓ | | | | |
| 2. | Anita Lee (G1) | AESO | | ✓ | | | | | | | | |
| 3. | Darrel Pace (G5) | AL Electric Coop Inc | | | | | | | | | | |
| 4. | Helen Stines (G5) | Alcoa Power Generating, Inc | | | | | | | | | | |
| 5. | Marion Lucas (G5) | Alcoa Power Generating, Inc | | | | | | | | | | |
| 6. | Eugene Warnecke (G5) | Ameren | | | | | | | | | | |
| 7. | E. Nick Henery (G2) | APPA | ✓ | | | | | | | | | |
| 8. | Jerry Smith (G7) (I) | APS | ✓ | | | | | | | ✓ | | |
| 9. | Kiet Nguyen (G5) | Assoc Electric Coop, Inc | | | | | | | | | | |
| 10. | Zack Stica (G5) | Assoc Electric Coop, Inc | | | | | | | | | | |
| 11. | Chris Bradley (G5) | Bg Rivers Electric Corp | | | | | | | | | | |
| 12. | Abbey Nulph | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 13. | Rebecca Berdahl (G7) | BPA | | | | | | | | | | |
| 14. | Steve Knudsen (G7) (I) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 15. | Brent Kingsford (G1) (I) | CAISO | | ✓ | | | | | | | | |
| 16. | Dave Lunceford (G7) | CAISO | | | | | | | | | | |
| 17. | Robert Walker | Cargill Power Markets, LLC | | ✓ | | | | ✓ | | | | |
| 18. | Ed Thompson (G3) | ConEdison | | | | | | | | | | |
| 19. | Greg Rowland | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 20. | Bob Crosier (G5) | E.ON U.S. Services Inc. | | | | | | | | | | |
| 21. | Joachim Francois (G5) | Entergy | | | | | | | | | | |
| 22. | Narinder Saini | Entergy Services, Inc. | ✓ | | | | | | | | | |
| 23. | Steve Myers | ERCOT | | ✓ | | | | | | | | ✓ |
| 24. | Bob Schoneck | Florida Power & Light Company | ✓ | | | | | | | | | |
| 25. | Don McInnis | Florida Power & Light Company | ✓ | | | | | | | | | |
| 26. | Kiko Barredo | Florida Power & Light Company | ✓ | | | | | | | | | |
| 27. | John Odom | Florida Reliability Coordinating Council | | | | | | | | | | ✓ |
| 28. | L. Earl Fair (G2) | Gainesville Regional Utilities | ✓ | | | | | | | | | |
| 29. | Robin Wiley (G5) | Georgia Transmission Corporation | | | | | | | | | | |
| 30. | Ross Kovacs (G5) | Georgia Transmission Corporation | | | | | | | | | | |
| 31. | Kevin Conway | Grant County PUD #2 of WA | | | | ✓ | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 32. | Roger Champagne | HQTE | ✓ | | | | | | | | | |
| 33. | Biju Gopi (G3) | IESO | | ✓ | | | | | | | | |
| 34. | Ron Falsetti (G1) (I) | IESO | | ✓ | | | | | | | | |
| 35. | Lou Ann Westerfieldd (G7) | IPUC | | | | | | | | | | |
| 36. | Kathleen Goodman (G3) (I) | ISO-NE | | ✓ | | | | | | | | |
| 37. | Matt Goldberg (G1) | ISO-NE | | ✓ | | | | | | | | |
| 38. | Brian Thumm | ITC Transmission | ✓ | | | | | | | | | |
| 39. | Michael Gammon | Kansas City Power & Light | ✓ | | | | | | | | | |
| 40. | Sueyen McMahon (G7) | LADWP | | | | | | | | | | |
| 41. | Allan Silk | Manitoba Hydro | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 42. | Jerry Tang (G5) | MEAG Power | ✓ | | | | | | | | | |
| 43. | Dennis Kimm | MidAmerican Energy Co | | | | | | ✓ | | | | |
| 44. | Larry Middleton (G5) | Midwest ISO | | | | | | | | | | |
| 45. | Renuka Chatterjee (G5) | Midwest ISO | | | | | | | | | | |
| 46. | Bill Phillips (G1) | MISO | | ✓ | | | | | | | | |
| 47. | Greg Campoli (G3) | New York ISO | | ✓ | | | | | | | | |
| 48. | Michael Calimano | New York ISO | | ✓ | | | | | | | | |
| 49. | Matt Schull (I) (G2) | North Carolina MPA | ✓ | | | | | | | | | |
| 50. | Guy V. Zito (G3) | NPCC | | | | | | | | | | ✓ |
| 51. | Mike Calimano (G1) | NYISO | | ✓ | | | | | | | | |
| 52. | Ralph Rufrano (G3) | NYPA | ✓ | | | | | | | | | |
| 53. | Ralph Rufrano (G3) | NYPA | ✓ | | | | | | | | | |
| 54. | Al Adamson (G3) | NYSRC | | | | | | | | | | ✓ |
| 55. | Mark Ringhausen | ODEC | | | | ✓ | | | | | | |
| 56. | Chifong Thomas | Pacific Gas & Electric Company | ✓ | | | | | | | | | |
| 57. | Alicia Daughtery (G1) | PJM | | ✓ | | | | | | | | |
| 58. | Donald Williams (G5) | PJM | | | | | | | | | | |
| 59. | Brett Koelsch | Progress Energy Carolinas | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 60. | Phil Creech (G5) | Progress Energy Carolinas | | | | | | | | | | |
| 61. | James Eckelkamp | Progress Energy Marketing | | | | | ✓ | | | | | |
| 62. | Al McMeekin (G4) (G5) | SC Electric and Gas | ✓ | | | | | | | | | |
| 63. | Ckay Young (G4) | SC Electric and Gas | ✓ | | | | | | | | | |
| 64. | Gene Delk (G4) (G5) | SC Electric and Gas | ✓ | | | | | | | | | |
| 65. | Stan Shealy (G4) | SC Electric and Gas | ✓ | | | | | | | | | |
| 66. | Carter Edge (G5) | SEPA | | | | | | | | | | |
| 67. | Derelyn Smith (G5) | SEPA | | | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 68. | John Troha (G5) | SERC | | | | | | | | | | |
| 69. | Ken Keels (G5) | SERC | | | | | | | | | | ✓ |
| 70. | Bob Schwermann (G7) | SMUD | | | | | | | | | | |
| 71. | Shannon Black (G7) | SMUD | | | | | | | | | | |
| 72. | Tadd Simms (G7) | SMUD | | | | | | | | | | |
| 73. | Chad Cooper (G5) | SC Electric and Gas | | | | | | | | | | |
| 74. | Stan Shealy (G5) | SC Electric and Gas | | | | | | | | | | |
| 75. | Bryan Hill (G5) | Southern Co Services | | | | | | | | | | |
| 76. | DuShaune Carter (G5) (G6) | Southern Co Services | | | | | | | | | | |
| 77. | Doug McLaughlin (G6) | Southern Co Services | ✓ | | | | | | | | | |
| 78. | Jim Busbin (G6) | Southern Co Services | ✓ | | | | | | | | | |
| 79. | John Lucas (G6) | Southern Co Services | ✓ | | | | | | | | | |
| 80. | Keith Calhoun (G6) | Southern Co Services | ✓ | | | | | | | | | |
| 81. | Marc Butts (G6) | Southern Co Services | ✓ | | | | | | | | | |
| 82. | Roman Carter (G6) | Southern Co Services | ✓ | | | | | | | | | |
| 83. | Ron Carlesn (G6) | Southern CoServices | ✓ | | | | | | | | | |
| 84. | Steve Corbin (G6) | Southern Co Services | ✓ | | | | | | | | | |
| 85. | Charles Yeung (G1) | SPP | | | | | | | | | | ✓ |
| 86. | Jonathan Hayes (G5) | SPP | | | | | | | | | | |
| 87. | Terri Kuehneman (G7) | SRP | | | | | | | | | | |
| 88. | Ann Scott | Tenaska | | | | | | ✓ | | | | |
| 89. | Raquel Agular (G7) | Tucson Electric | ✓ | | | | | | | | | |
| 90. | Doug Bailey (G5) | TVA | | | | | | | | | | |
| 91. | Mike Wells (G7) | WECC | | | ✓ | ✓ | ✓ | | | | | |

G1 – ISO/RTO Council
G2 - NPPA
G3 - NPCC CP9 Reliability Standards WG
G4 – SCE&G
G5 – SERC ATC WG
G6 – Southern Co
G7 - WECC MIC MIS ATC Task Force

**Index to Questions, Comments and Responses:**

1. **This is the proposed definition for 'Existing Transmission Commitments (ETCs)' — Any combination of Native Load uses, Contingency Reserves not included in Transmission Reliability Margin or Capacity Benefit Margin, existing commitments for purchases, exchanges, deliveries, or sales, existing commitments for transmission service, and other pending potential uses of Transfer Capability. Is this definition sufficient to calculate the ETC in a consistent and reliable manner? If not, please explain.**

**Summary Consideration:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify (in MOD-028, MOD-029, and MOD-030) the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components.

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| ERCOT | | | ERCOT does not have a transmission service market. Therefore, this concept does not have meaning in ERCOT operations as described in this definition. |
| **Response:** Agreed. However, if ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | | | |
| APPA | | ☑ | The definition is too vague to be used as a major component of the ATC Calculations. Therefore a Standard needs to be developed to determine the rules for what is ETC, where to post ETC, and the requirements for archiving the ETC for future Compliance Records and Auditing. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. | | | |
| BPA | | ☑ | This definition merely describes a universe of explicit contractual or planning commitments that can be included in the calculation of ETC. To actually calculate ETC, however, these commitments must be translated into a representation of power transfers, i.e., the use of transfer capability. BPA does not agree that ETC should be addressed as a subcomponent of MOD-001-1 as suggested in P243 or Order 890; rather, it should be addressed in its own standard. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the | | | |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| components. | | | |
| Cargill | | ☑ | Phrase "other pending potential uses" too broad and open to interpretation and could allow discrimination. Order 890 states that ETC should include: native load commitments, grandfathered transmission rights, point-to-point reservations, rollover rights, and other uses identified through the NERC process. We feel that "other pending potential uses" does not comply with Order 890. All components of ETC should be specifically defined. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components, and includes a clearer definition of what was intended with the phrase, **"**pending potential uses of Transfer Capability". | | | |
| Duke Energy | | ☑ | The definition of ETC is too ill defined. There probably needs to be a separate standard for ETC (as exists for TRM and CBM). "Native load" should be "Network/Native load". All Contingency Reserves has too general to be used for ETC calculation - only reserves considered under TRM and CBM should be allowable for ETC calculation. What are the "existing commitments for purchases, exchanges, deliveries, or sales" that do not fall under the "existing commitments for transmission service" category? This phrase should be eliminated from the definition. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. The phrase, 'existing commitments for transmission service' is not used in the revised standards (MOD-001, MOD-028, MOD-09-29, MOD-030). | | | |
| Entergy | | ☑ | Definition of ETC is broad and can not be used to calculate the ETC in a consistent and reliable manner. Since ETC will vary depending on what ATC calculations this is used for, its components can vary. For example, for Firm ATC calculation, there is no need to include non-firm reservations. A detailed Standard could to be developed or details included in MOD-001 for ETC calculations that should describe requirements and components to be included in ETC calculations. However, in view of para 243 of FERC Order 890, ETC should be addressed by including the requirements in MOD-001 rather than through a separate reliability standard. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. | | | |
| Grant County PUD | | ☑ | I have no specific suggestions, but in reading the definition for the first time, I am not sure how to interpret this. I have had to read it several times, and could interperet the defintion several ways as to our situation. Dynamic (and or psudo tie) uses for wind, and hydro generation, grandfathered system rights, and flow through from other systems that don't follow schedule paths, but physical paths, could all be problematic. |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. | | | |
| ITC Transco | | ☑ | Other pending potential uses" does not sound like an existing commitment. The definition should reference "other uses" or "other pending uses" or "other committed uses" but a "potential use" is not a commitment. There are lots of potential uses of the transmission system, but the only ones that matter in the context of this definition are those for which transmission capacity needs to be reserved. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. The proposed requirements provide an interpretation of what was intended with the use of the phrase, 'other pending potential uses'. | | | |
| KCPL | | ☑ | This definition is open ended. It would be better as a definition to include all components that can be thought of and amend the definition as the need arises. This definition needs to stand alone and not make reference to TRM and CBM. If there are items missing from the TRM and CBM that need to included in them, then it should be included and not left for ETC to clean up. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components.<br><br>Note that the drafting team did use CBM and TRM in the revised standards (MOD-028, MOD-09, and MOD-030) because these acronyms were used in FERC Order 890. | | | |
| Manitoba Hydro | | ☑ | Manitoba Hydro believes that the definition is close but you would have to develop the definition further to describe when it is appropriate to describe reserves as ETC. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. | | | |
| MidAmerican | | ☑ | The definition of ETC must be modified to comply with Order 890, Paragraph 244. In addition, the definition does not define "other pending potential uses" of Transfer Capability, or explain how the other individual components of ETC are to be calculated. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. The proposed requirements provide an interpretation of what was intended with the use of the phrase 'other pending potential uses'. | | | |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| MISO | | ☑ | The definition for ETC is very generic. With the FERC Order 890 requirements of transparency in ATC/AFC calculations, this definition needs to be revisited to add more speficity to it. The definition specifically needs to include modeling of transmission commitments due to transmission service from other transmission providers. Midwest ISO is currently addressing this through two approaches – 1. Seams agreements that address modeling of transmission commitments from other entities. 2. a forecast error term which is currently under development that will address AFC predictions in real time to accommodate for errors in load, generation outage and loopflow forecasts. The standard needs to be revisited to make the computation of transmission commitments in both AFC and ATC methodologies transparent to transmission customers. Include thirdy party generation to load impacts. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. Transparency will be a key element in all standards developed pertaining to ATC. The Team will address modeling and forecasting concerns. | | | |
| MRO | | ☑ | It is not clear in the definition whether the words existing commitments is to apply only to purchases or also exchanges, deliveries, or sales. In other words, is it the intent of the Drafting Team that only existing commitments for exchanges, deliveries, or sales be included in ETC? If it is the latter than the definition should be changed to say existing commitments for exchanges, existing commitments for deliveries, or existing commitments for sales or else use punctuation such as semi-colons to make clear the meaning. If it is the former than the MRO suggests that exchanges deliveries, or sales be moved before the words existing commitments for purchases, such as exchanges, deliveries, or sales, existing commitments for purchases, existing commitments for transmission services, etc. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. Note that in the revised standards (MOD-001, MOD-028, MOD-029, MOD-030) the term, 'existing commitments' is not used. | | | |
| ODEC | | ☑ | The last catch all phrase of 'other pending potential uses of Transfer Capability' causes great concern. What does this mean? It is not clear, therefore, the definion of ETC is not clear. Should non-firm schedules be included, it is not clear from this definion, but it needs to be very clear so everyone is calulcating ETC the same way. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. . The revised standards (MOD-001, MOD-028, MOD-029, MOD-030) do not include the phrase, 'other pending potential uses'. | | | |
| SCE&G and<br>SERC ATCWG<br>Southern | | ☑ | The ETC definition reference to "Native Load uses" is not applicable to ATC calculations. By definition, a transfer analysis determines the amount of import (or export) capacity possible in addition to the native load service modeled in the base case. Internal transfers to serve network loads are not included in TTC values and should not be subtracted from TTC to obtain ATC. Conversely, since |

| **Question #1** | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | TFC is similar to a facility rating, not a (n-1) transfer analysis , the impacts of serving native load must be considered in calculating AFC and are therefore appropriate in an AFC calculation.<br><br>Either the ETC definition should be changed to reflect the differences between ATC and AFC calculations or the ATC formula should be changed to remove ETC from the calculation. This could be accomplished by using the following ATC calculations.<br><br>Firm ATC = TTC - CBM - TRM - Firm Interface Commitments Non-firm ATC = TTC - All Interface Commitments + Postbacks of Unscheduled Service<br><br>In addition, the ETC definition should be modified to remove references to Contingency Reserves, which are not an Existing Transmission Commitment. The ATC equations allow for uncertainties such as CBM and TRM. To the extent additional reserve margins are required, they should accounted for as such in the AFC or ATC equations, not by lumping them into ETC. Also, references to pending uses should be removed. ETC should include only commitments, not potential uses. A suggested ETC definition is provided below.<br><br>ETC: Used in the context of calculating AFC, ETC reflects the impacts of power flows associated with serving native loads, commitments for firm and non-firm transmission service, and any other commitments for transmission service not covered by OATT requirements. |
| **Response:** Due to the different methods for determining TTC and ATC these comments may apply in some regions and not in other regions. Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. NAESB is expected to write a business practice that will provide more details for some of these items – for example NAESB is expected to clarify what can be included in Native Load. | | | |
| WECC ATC Team | | ☑ | Although the definition is sufficient to “describe” Existing Transmission Commitments, it is not sufficient to “calculate the ETC.” ETC is an essential variable in the ATC calculation on par with TTC, CBM and TRM. As such, ETC should be addressed in its own freestanding standard to be consistent with the other ATC variables and to further promote clarity, consistency and transparency of this essential ATC component. This group does not concur that ETC should be addressed as a subcomponent of MOD-01 as stipulated in P243 of Order 890.<br><br>To bring the definition in line with Order 890, P. 244, this Team suggests:<br><br>The following language should be used as the definition for Existing Transmission Commitments. |

| Question #1 | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| | | | To bring the definition into accord with Order 890, the Team suggests striking any reference to Contingency Reserves from the definition.<br><br>Existing Transmission Commitments (ETC):<br>Any combination of:<br>1. Native Load commitments (including network service),<br>2. Load forecast error<br>3. Losses<br>4. Existing commitments for energy purchases, exchanges, deliveries, or sales and existing commitments for transmission service,<br>5. Appropriate point-to-point reservations<br>6. Rollover rights associated with long-term service<br>7. Other pending potential uses of transfer capability, either TTC or AFC, identified through the NERC process. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. | | | |
| IESO | ☑ | ☑ | We agree with most of the components except "…other pending potential uses of Transfer Capability". This component is subject to interpretation and it is difficult to demonstrate a quantifiable need for the inclusion of this component. Also, we question the need to specify "exchanges" and "deliveries" given that "purchases" and "sales" are already included in the definition. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. The revised standards (MOD-001, MOD-028, MOD-029, and MOD-030) do not include the phrase, 'other pending potential uses'. | | | |
| NYISO<br>CAISO<br>ISO-NE | ☑ | | We agree with most of the components except "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion. Also, we question the need to specify "exchanges" and "deliveries" given that purchases and sales are already included. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the | | | |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| components. The revised standards (MOD-001, MOD-028, MOD-029, and MOD-030) do not include the phrase, 'other pending potential uses'. | | | |
| HQT | ☑ | | We question the use of "other pending potential uses of Transfer Capability". This component is subject to interpretation and is difficult to demonstrate the need and quantify it for inclusion. |
| **Response:** Most commenters disagreed with the proposed definition – several suggestions were provided for improving the definition, all requiring more details. The drafting team elected to remove the definition, and instead specify the components of ETC as bulleted requirements. The proposed requirements include the components that go into ETC and provide a detailed method for determining each of the components. The revised standards (MOD-001, MOD-028, MOD-029, and MOD-030) do not include the phrase, 'other pending potential uses'. | | | |
| FRCC | ☑ | | |
| NPCC CP9 | ☑ | | |
| Progress Energy | ☑ | | |
| AECI | ☑ | | |
| SPP | ☑ | | |
| APS | ☑ | | |

2. **This is the proposed definition for 'Transmission Service Request' — A service requested by the Transmission Customer to the Transmission Service Provider that may move energy from a Point of Receipt to a Point of Delivery. Should this definition be expanded or changed?**

**Summary Consideration:** There was an error in the question – the proposed definition that was posted with the standard did not include the word, 'may – the proposed definition posted with the standard was:

Transmission Service Request: A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

The proposed definition uses the already approved definition of 'Transmission Service' and adds words to support 'request'. The approved definition of Transmission Service is: Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

The drafting team did not make any changes to the proposed definition.

<table>
<tr><th colspan="4">Question #2</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>ERCOT</td><td></td><td></td><td>ERCOT does not have a transmission service market. Therefore, this concept does not have meaning in ERCOT operations as described in this definition.</td></tr>
<tr><td colspan="4">Response: Agreed. However, if ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration.</td></tr>
<tr><td>APPA</td><td>☑</td><td></td><td>A Transmission Service Request is a request to reserve Transmission Capacity. If accepted and confirmed, it is not necessary for the Transmission Customer to move energy on this Transmission Capacity. In fact, it may be used for operating reserves and energy would only be scheduled on this capacity if there was an emergency. The definition should read in a manner that the Transmission Customer is requesting Transmission Capacity from a point of receipt and points of delivery.</td></tr>
<tr><td colspan="4">Response: Agreed. The purpose of this definition was not to imply that energy must be scheduled or moved along the path for which the Transmission Capacity was reserved. The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." This should only imply that the ability to move energy along a transmission path should be available, if necessary.</td></tr>
</table>

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | |
| BPA | ☑ | | The definition as written implies that the request is for the physical movement of power from a specific generator to a requested point of delivery. In fact, the underlying nature of the service requested is to inject power into the grid at at a point of receipt, and to withdraw a like amount of power at a specific point on the grid for the benefit of an identified load.<br><br>It is also not clear that a request for Network Integration Transmission Service would fall within this definition, because it may involve multiple PORs and PODs. |
| **Response:** The purpose of this definition was not to imply that energy must be scheduled or moved along the path for which the Transmission Capacity was reserved. The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| CAISO<br>ISO-NE | ☑ | | Definition is already sufficient and should not be expanded or changed.<br><br>The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "**and/or Ancillary/Services"** after the word "energy". The SDT should also review the definition of transmission service for consistency.<br><br>The definition should include reference to ultimate Source and Sink. Add to end of proposed definition "… and from ultimate Source to ultimate Sink." |
| **Response:**<br>The SDT thinks the comment "Definition is already sufficient and should not be expanded or changed" was made in error.<br>The SDT does not agree the ultimate Source and Sink are a requirement of every Transmission Service Request.<br>The reservation of Ancillary Services is a separate FERC requirement. The drafting team believes that Ancillary Services are not part of ATC/AFC, and should not be included in the definition of a transmission service request. The NERC glossary already has a definition for Ancillary Services. | | | |
| Duke Energy | ☑ | | 'Transmission Service Request' - An OASIS request by the Transmission Customer to reserve transmission capacity for the purpose of moving energy from a point of receipt to a point of delivery. |
| **Response:** The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| FRCC | ☑ | | Should specify that it must be done on OASIS and should be broad enough to include network integration transmission service also. Suggested wording: A service requested on the OASIS by a transmission customer of the transmission service provider to move energy out of, across, or into the transmission service provider's transmission system. |
| **Response:** The proposed definition of Transmission Service Request was intended to be very general and not to define a detailed process. | | | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| Grant County PUD | ☑ | | Who's POR or POD? I am sure I know what the intent is, some may read this, as written to mean the whole path. |
| **Response:** The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| IRC | ☑ | | The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "and/or A/S" after the word "energy". The SDT should also review the definition of transmission service for consistency.<br><br>The definition should include reference to ultimate Source and Sink. Add to end of proposed definition "… and from ultimate Source to ultimate Sink." |
| **Response:** The proposed definition of Transmission Service Request was intended to be very general and not to define a detailed process. The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery."<br>Ultimate Source and Sink are not required of every Transmission Service Request. | | | |
| ITC Transco | ☑ | | It may be semantics, but NITS generally does not have "a point" of receipt or delivery. The definition could refer to sources and sinks rather than PORs and PODs.<br><br>Also, why is this term being defined? It is virtually identical to the definition of Transmission Service, only with the phrase "provided to" replaced by "requested by." The Standards should not define the obvious. |
| **Response:** NITS should have a separate request for each different POR/POD combination for ATC calculation purposes. The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| MidAmerican | ☑ | ☑ | This is not a proposed definition. This is the current definition in the NERC glossary.<br>The new definition should defines the transmission service request as a request for transmitting capacity and energy. |
| **Response:** The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| MISO | ☑ | | This definition itself would have been fine if the terms "Point of Receipt" and "Point of Delivery" were consistently treated by the various transmission providers. With the FERC order 890 requirements of consistency in AFC/ATC calculations, the standards needs to be revisited to address the consistent |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | and transparent treatment of Point of Receipt, Point of Delivery, Source and Sink usage as applicable to a TSR within AFC/ATC calculations. A suggested industry wide definition for Transmission Service Request could be "a request for using the transmission system submitted to a transmission provider (typically through an OASIS system) to move power (MWs) either into, out of, within or across the footprint of the transmission provider (with specific start time and stop times, class of service (firm/non-firm) and service increment (hourly, daily weekly etc.,)" |
| **Response:** The SDT has addressed the directives in FERC order 890 and has made some conforming changes to the standard as suggested. The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| MRO | ☑ | | The OATT definition for Point-To-Point Transmission Service indicates that it is a service for the receipt of capacity and energy at designated Points of Receipt and the transmission of such capacity and energy to designated Points of Delivery. The definition of Transmission Service Request should be revised to state that it is a request to move CAPACITY and energy from a Point of Receipt to a Point of Delivery. The added word is stated in all caps. |
| **Response:** The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| NCMPA | ☑ | | A Transmission Service Request is a request to reserve Transmission Capacity. If accepted and confirmed, it is not necessary for the Transmission Customer to move energy on this Transmission Capacity. In fact, it may be used for operating reserves and energy would only be scheduled on this capacity if there was an emergency. The definition should read in a manner that the Transmission Customer is requesting Transmission Capacity from a point of receipt and points of delivery. |
| **Response:** The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| NYISO | ☑ | | Definition is already sufficient and should not be expanded or changed.<br><br>The definition should be modified to recognize the need for transmission requests for A/S capacity, not just actual energy. Insert "and/or A/S" after the word "energy." The SDT should also review the definition of transmission service for consistency. |
| **Response:** The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| Southern | ☑ | | Is the service definition to include point-to-point and network. Suggested TSR definition is provided below:<br><br>TSR: The act of making a request for reservation and transmission of capacity and energy on either a |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | firm or non-firm basis from the Point(s) or Receipt to the Point(s) of Delivery under Part II or III of the Tariff. |
| **Response:** The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." . | | | |
| SPP | ☑ | | Definition should include reference to Source, Sink .<br>Add to end of proposed definition …… and from ultimate Source to ultimate Sink. |
| **Response:** The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." The ultimate Source and Sink are not a requirement of every Transmission Service Request. | | | |
| Entergy | ☑ | | |
| HQT | ☑ | ☑ | Point of receipt and point of delivery shall be defined. Considerations shall be taken for POR and POD from different asynchronous Interconnection. |
| **Response:** The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery."<br>Point of Receipt and Point of Delivery are already approved terms in the NERC Glossary. | | | |
| ODEC | | ☑ | TSR is just a request for service. Definion reads that way so it is okay. |
| **Response:** Agree. | | | |
| KCPL | | ☑ | This definition has already been adopted in the current NERC Glossary and is sufficient. |
| **Response:** Not exactly – the definition in the NERC Glossary only addressed Transmission Service. The intent was to expand upon the already approved term, "Transmission Service," in the NERC Glossary to describe the act of making a request for Transmission Service. The definition of Transmission Service in the NERC Glossary is "services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery." | | | |
| IESO | | ☑ | |
| Manitoba Hydro | | ☑ | |
| Progress Energy | | ☑ | |
| SCE&G and SERC ATCWG | | ☑ | |
| NPCC CP9 | | ☑ | |
| Cargill | | ☑ | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| AECI | | ☑ | |
| APS | | ☑ | |
| WECC ATC Team | | ☑ | |

3. **This is the proposed definition for 'Flowgate' — A single transmission element, group of transmission elements that may include associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Transfer Distribution Factors are used to approximate MW flow impact on the flowgate caused by power transfers.**

**This is the definition of Flowgate in the NERC Glossary of Terms Used in Reliability Standards: A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.**

**Which definition do you prefer?**

**Summary Consideration:** Based on stakeholder comments, the drafting team removed the second sentence from the proposed definition so that the revised proposed definition is:

A single transmission element, or a group of transmission elements, or a single transmission element with one or more contingencies, or a group of transmission elements with one or more contingencies intended to model MW flow impact relating to transmission limitations and transmission service usage.

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Proposed** | **Already Approved** | **Comment** |
| ERCOT | | | ERCOT does not typically use the term "Flowgate". ERCOT analysis considers monitored elements and a list of contingencies used in contingency analysis. However, the definition of monitored element, while similar to Flowgate, does not require the inclusion of associated contingencies. Both definitions, as prescribed, do not have meaning in ERCOT operations. |
| **Response:** Agreed. However, if ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | | | |
| APPA | ☑ | | Flowgate are also used in the Western Interconnection where there is not an IDC. |
| BPA | ☑ | | Although the proposed definition is superior to the existing NERC definition, BPA |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Proposed** | **Already Approved** | **Comment** |
| | | | believes that it may be too expansive. Specifically, the proposed definition does not clarify what is contemplated by the term "any associated contingencies". If the proposed standards are intended to ensure specificity and transparency of the contingencies, margins and/or uncertainties that may be considered when determining ATC, then BPA thinks any contingencies should be explicitly identified and quantified in the determination of TTC/TFC, TRM and/or CBM, and not in the definition of a flowgate. Also, it is not clear why a definition for transfer distribution factors is included in the definition of a flowgate. It would seem more appropriate to provide a separate stand-alone definition of transfer distribution factors. |
| **Response:** The Drafting Team feels the word contingencies is an industry accepted term that is defined in the NERC glossary as, "The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." By using the term "Any associated contingencies", flexibility is given to allow a flowgate to be defined in such a way to keep the system reliable. The second sentence is not a definition of transfer distribution factors. It was intended to show how the MW impact of a power transfer can be applied to a flowgate. The Drafting Team removed the sentence that included text about transfer distribution factors. | | | |
| Duke Energy | ☑ | | Delete the second sentence of the proposed definition. |
| **Response:** The Drafting Team agrees and removed the second sentence from the definition. | | | |
| FRCC | ☑ | | Last sentence of new definition is not necessary. It is extraneous to the definition. |
| **Response:** The Drafting Team agrees and removed the second sentence from the definition. | | | |
| HQT | ☑ | | "any associated contingency" needs to be explained. Why should contingencies be associated to an element or group of transmission elements? |
| **Response:** The majority of monitored elements have a worst contingency that has the largest negative impact on the flows on that monitored element. When using flowgates to analyze a transmission system, instead of studying all contingencies for a monitored element, the worst contingency may be coupled with the monitored element and is called a flowgate. That is why when defining a flowgate the flexibility is given to include "any associated contingency or contingencies". However, as defined, it is not necessary to associate a flowgate with a contingency. | | | |
| KCPL | ☑ | | Propose the following refinement to the proposed definition:<br>Flowgate - a single transmission element or group of transmission elements that may include an associated transmission contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage by the use of Transfer Distribution Factors.<br><br>Transmission Distribution Factor is not included in the NERC Glossary. Should Transmission Distribution Factor be defined or should it be excluded from the above definition? |
| **Response:** The Drafting Team agrees and removed the second sentence from the definition. | | | |
| ODEC | ☑ | | I prefer the new defiinion, but think we might be able to improve on it. |

| Question #3 | | | |
|---|---|---|---|
| Commenter | Proposed | Already Approved | Comment |
| **Response:** Several commenters agreed that the definition needs modification and the Drafting Team agrees and removed the second sentence from the definition. | | | |
| Southern | ☑ | | Make sure that the correlation to other standards is correct when making this change. |
| **Response:** We agree. The other standards will be examined. | | | |
| SCE&G and SERC ATCWG | ☑ | | |
| SPP | ☑ | | |
| WECC ATC Team | ☑ | | |
| MEAG Power | ☑ | | |
| MidAmerican | ☑ | | |
| MRO | ☑ | | |
| NYISO | ☑ | | |
| AECI | ☑ | | |
| APS | ☑ | | |
| CAISO | ☑ | | |
| IESO | ☑ | | |
| IRC | ☑ | | |
| ISO-NE | ☑ | | |
| ITC Transco | ☑ | | |
| Entergy | ☑ | | |
| Progress Energy | ☑ | | |
| Cargill | | ☑ | But change to, "A designated point, element or group of elements on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions." |
| **Response:** Because the Western Interconnection does not use an IDC, the drafting team felt it should be removed from the definition. Flowgates can also be used in different types of load flow analysis not just in the IDC and therefore we felt a more general definition was warranted. | | | |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Proposed** | **Already Approved** | **Comment** |
| PG&E | | ☑ | The alternative definition is confusing by including contingenies with transmission elements. It seems to assume that the contingencies that should be considered for each flowgate are fixed, but in reality, the contingencies that would have the most impacts on the power flow through a flowgate changes as the system change. |
| **Response:** Flowgates are not necessarily only a monitored element. The majority of monitored elements have a worst contingency that has the largest negative impact on the flows on that monitored element. When using flowgates to analyze a transmission system, instead of studying all contingencies for a monitored element, the worst contingency is coupled with the monitored element and is called a flowgate. It is true that the contingencies that would have the most impacts on the power flow through an element can change as a system changes. That is why it is important to reevaluate flowgates often. | | | |
| Grant County PUD | | ☑ | We start to create a problem if standards have their own meanings for a term. This creates an abiguity and needs to be avoided at all costs. |
| **Response:** The drafting team agrees. We are proposing changing the definition in the NERC Glossary which is used by all standards. | | | |
| Manitoba Hydro | | ☑ | Between the two definitions the second is clear enough to be used in a standard. Manitoba Hydro believes you could work on the proposed definition to improve it without changing the meaning. For example, the phrase "model MW flow impact relating to transmission limitations and transmission service usage" could be replaced with "model congestion through all Horizons"<br><br>I suggest that the team has erred in including the contingencies in the definition of the flowgate. The contingency may define what type of flowgate it is, e.g. OTDF as compared to PTDF, and will certainly define where the location of the flowgate is but it does not define what a flowgate is. A flowgate could be created by a planned/forced transmission outage, a planned/forced generator outage, or a by an interregional stability concern. It may be good practice to include the contingency in the naming of flowgates, e.g. x for loss of y, but in my opinion y is not part of the flowgate.<br><br>In defining a flowgate as a single transmission element or a group of transmission elements, I believe the team would be doing a great service to the industry by determining if one type of flowgate, single transmission element or group of transmission elements, is preferable. There is a concern that multi-facility flowgates provide less overall reliability (by their proxy nature) than single element flowgates. The team should also determine if and when it is appropriate to use proxy flowgates.<br><br>Finally I believe "that Transfer Distribution Factors are used to approximate MW flow on a Flowgate… " is actually a second definition (Flowgate Impact). The information is useful but extraneous when defining what a flowgate is. |
| **Response:** Because the Western Interconnection does not use an IDC, the drafting team felt it should be removed from the definition. Flowgates can also be used in different types of load flow analysis not just in the IDC and therefore we felt a more general definition was | | | |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Proposed** | **Already Approved** | **Comment** |
| warranted. Flowgates are not necessarily only a monitored element. The majority of monitored elements have a worst contingency that has the largest negative impact on the flows on that monitored element. When using flowgates to analyze a transmission system, instead of studying all contingencies for a monitored element, the worst contingency is coupled with the monitored element and is called a flowgate. That is why when defining a flowgate the flexibility is given to include "any associated contingency(ies)". The Drafting Team feels the word contingencies is an industry accepted term that is defined in the NERC glossary as, "The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." By using the term "Any associated contingencies", flexibility is given to allow a flowgate to be defined in such a way to keep the system reliable.<br>The second sentence is not a definition of flow impact. It was intended to show how the MW impact of a power transfer can be applied to a flowgate. The Drafting Team now feels this second sentence is superfluous and has removed it. | | | |
| MISO | | | Neither – The proposed definition and NERC definition creates the impression that any set of transmission elements could be used to make up a flowgate resulting in inconsistencies in flowgate usage between selling transmission service and curtailing transmission service. "Flowgates are pre determined set of constraints on the transmission system that are expected to experience loading problems in real-time. " This should result in neighbouring transmission providers using consistent set of flowgates for evaluating transmission service. The requirements should address making this list of flowgates and their parameters transparent. |
| **Response:** The drafting team is strengthening the coordination and transparency in the standards referring to flowgates. The revised proposed standards do address the transparency of flowgates and their parameters and also addresses the coordination of flowgates. | | | |

4. The drafting team believes that formal definitions are needed for the various time frames used in the standard. As a straw man, the drafting team would like to have industry comment on the proposed definitions below:

**Operating Horizon** — Time frames encompassing same-day and real-time periods.
**Scheduling Horizon** — Time frames encompassing the day-ahead period.
**Operations Planning Horizon** — Time frames beyond the Scheduling Horizon up to 13 months
**Long-term Planning Horizon** — Time frames beyond the Operations Planning Horizon

Do you think that the above terms need to be defined for use in this standard — and if you do, then do you agree with the proposed definitions?

☐ N/A — these terms do not need to be defined for use in this standard

☐ The terms do need to be defined and I do agree with the proposed definitions

☐ The terms do need to be defined but I don't agree with the proposed definitions

**Summary Consideration:**
There was no consensus on this issue and rather than define these terms, the drafting team defaulted to using the descriptive language and terms used by FERC in Order 890.

| Question #4 | | | | |
|---|---|---|---|---|
| **Commenter** | **N/A** | **Do need to be defined and do agree.** | **Do need to be defined but don't agree.** | **Comment** |
| CAISO | ☑ | | | We do not agree but if there is a need to reference time periods in the requirements, they should be specified in the requirements themselves and not as universal terms due to the lack of specificity in these. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| Duke Energy | ☑ | | | Need to define the precise time periods in Operating Horizon and Scheduling Horizon (i.e. 12:00 midnight, etc.) |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| Entergy | ☑ | | | Time frames (real-time; same day; day-ahead; and from day-ahead up to 13 months) as included in the standard are clear. There is no need to define these terms in this standard as these may conflict with the intent of these terms used in other standards. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| IRC<br>ISO-NE | ☑ | | | We do not agree but if there is a need to reference time periods in the requirements, they should be specified in the requirements themselves and not as universal terms due to the lack of specificity in these. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |

| Question #4 | | | | |
|---|---|---|---|---|
| **Commenter** | **N/A** | **Do need to be defined and do agree.** | **Do need to be defined but don't agree.** | **Comment** |
| MidAmerican | ☑ | | | MidAmerican is unable to find any of these terms in the standard as it's currently drafted.<br><br>If these terms are used in the standard, these terms should be revised to use 12 months or longer to refer to the long-term planning horizon and operations planning horizon for up to 12 months as used in other standards such as TPL-001 through TPL-004.<br><br>To the extent these terms *are* used in the standard, we believe the resolution of this question should be deferred until the standard is redrafted to be compliant with order No. 890.<br><br>If the proposed definitions are retained, it would appear that new definitions would be required for these terms:<br>– day-ahead<br>– real-time (Although this term is already defined in the NERC Glossary of Terms, the intent in MOD-001 may not match that existing definition.)<br>– same-day<br>– 13 months (This should be changed to 12 months to be consistent with the definition that is being clarified by TPL-001 through TPL-004.) |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| MISO | ☑ | | | These terms and frequency of calculations are business practices of each individual transmission provider. Defining these terms in the standard and only transmission providers using Network Response Method (AFC/ATC) calculations does not appear to be consistent with Order 890 requirements of consistency. The requirements should more along the lines of allowing each Transmission provider irrespective of the methodology used to make available business practices that describe the time horizons and frequency of calculations. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| NYISO | ☑ | | | |

| Question #4 | | | | |
|---|---|---|---|---|
| Commenter | N/A | Do need to be defined and do agree. | Do need to be defined but don't agree. | Comment |
| NCMPA | | ☑ | | Should the Scheduling Horizon be defined as "Time frames encompassing the *business* day-ahead period"? Most transmission customers schedule on Friday for Saturday, Sunday and Monday deliveries. Also, some transmission provider OASIS business practices recognize business days rather than calendar days. (e.g. Some TPs sell non-firm hourly transmission after noon for the next business day, which on Friday includes Saturday, Sunday and Monday.) |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| WECC ATC Team | | ☑ | | These definitions do not agree with the definitions identified in Order 890 (see P323) as follows:<br>Operating Horizon – day ahead and pre-schedule<br>Scheduling Horizon – same day and real-time<br>Planning Horizon – beyond the operating horizon<br>The fact that FERC and NERC do not agree on the definition of these terms confirms the need to formalize the definition. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| FRCC | | ☑ | | Requirement R11.5 should use the term " Long-term planning horizon" as defined above rather than " for use in the 13 months and longer time frame". |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| HQT | | ☑ | | Considerations should be made for the transition from the Scheduling and the operating. Exemple transition is performed each day at 16:00 |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| ODEC | | ☑ | | |
| IESO | | ☑ | | |
| KCPL | | ☑ | | |
| AECI | | ☑ | | |
| BPA | | ☑ | | |
| APPA | | | ☑ | This Standard does not need to redefine what the planners and operators |

| Question #4 | | | | |
|---|---|---|---|---|
| Commenter | N/A | Do need to be defined and do agree. | Do need to be defined but don't agree. | Comment |
| | | | | of the BES has already defined. The Regions, Reliability Coordinator, Planners and Transmission Operators have established what is the Planning Horizons (T >= 1 Year) and Operating Horizon (T< 1 Year). |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| APS | | | ☑ | To avoid confusion and future problems, the terms definitions should be consistent with Order 890. In which case, Operations and Long-Term Planning Horizons would not be broken out, rather would simply be "Planning Horizon." |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| ERCOT | | | ☑ | I am concerned that there may be multiple efforts underway on various SARs and Standards as well as the Operating Limit Definition Task Force that may be using variations of this concept. I do agree that a uniform understanding and set of terms for these timeframes would be useful and may help to avoid contradictions and confusion, but I am uncertain whether this standard is the place for this to be decided. They should not be offered as "definitions", which I understand the standards development process requires to become a part of the NERC Glossary. Perhaps the standard should clarify what is meant for the purposes of this standard, but it should not be proposed as official "definitions" which must apply in all standards.<br><br>In general, I believe that all of the horizons listed, with the exception of the "Scheduling Horizon" exist with some consistency of understanding (although not always with exactly the same durations specified). The Operations Planning "horizon" is typically discussed as representing from Real-Time through Day-Ahead and on up to one year. The "Planning Horizon" is typically discussed as representing one year and longer; this would correspond closely, but not exactly with the "Long-term Planning Horizon" proposed above. Some difficulty arises because many of the differing contractual agreements, organizational arrangements, and market rules define these terms differently at different locations. This may be true even for such arrangements which cross Regions or even Interconnections. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |

| Question #4 | | | | |
|---|---|---|---|---|
| Commenter | N/A | Do need to be defined and do agree. | Do need to be defined but don't agree. | Comment |
| Grant County PUD | | | ☑ | I would avoid the need to create more defined terms. Long lists of defined terms cause confusion and misunderstanding. Perhaps a simpler solution would be to use the term in the text, explain it there when it is first introduced, and then continue to use the term. This makes the document a little easier to read, and keeps the definition in context. It is my experience that in the effort to create a good document, we write at a level that is above many readers comprehension level. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| Manitoba Hydro | | | ☑ | In the Operations Planning Horizon, I believe that the word "up" should be removed. It is important to coordinate the length of the Horizons. This will allow all transmission providers to use similar assumptions when studying congestion on flowgates. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| ITC Transco | | | ☑ | For bettor or for worse, the Standards are now using violation mitigation time horizons. These include time horizons for "Long Term Planning," "Operations Planning," "Same Day Operations," "Real-Time Operations," and "Operations Assessment." The Transmission Planning Standards (notably TPL-001 through -004) have also had a near-term and a longer-term planning horizon to further segment the Long-term Planning Horizon. Rather that create yet another set of time horizons for this standard, NERC should consider standardizing the time horizons, or at least re-using some of them when they could suffice for a particular scenario. In this instance, it appears that the time horizons for MOD-001 could be made to work with the Time Horizons for violation mitigation with only a little bit of tweaking. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| MRO | | | ☑ | These terms should be used consistently across the standards and inserted in the NERC glossary. Having individual definitions in an individual standard will only lead to confusion. The Operations Planning Horizon should be less than one year. Other NERC standards such as TPL-001 through TPL-004 are established assuming that one year or more falls into the Long-term Planning Horizon. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| Progress Energy | | | ☑ | Differentiating between the Operating and Scheduling Horizons is unnecessary; There should only be one term for real time, current day, and next day operating periods. We would like to see "Operations" refer to |

| Question #4 | | | | |
|---|---|---|---|---|
| **Commenter** | **N/A** | **Do need to be defined and do agree.** | **Do need to be defined but don't agree.** | **Comment** |
| | | | | real time, today, and next day. "Operations Planning Horizon" should be changed to "Near-Term Planning Horizon". |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| Southern | | | ☑ | Scheduling and Operating definitions need to be swapped. These are defined in Order 890 paragraph 323. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |
| SPP | | | ☑ | We think terms need to be defined however they should be more general to allow for regional differences. |
| **Response:** At this point in time, the SDT has elected to use the horizons defined in order 890. | | | | |

5. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

**Summary Consideration:**
Most commenters suggested that the following terms need improved definitions and rather than try and obtain consensus on new definitions, the drafting team has elected to eliminate these as 'defined' terms:

- Rated System Path Method
- Network Response Method
- Existing Transmission Commitments

No changes were made to the following proposed definitions:

- Available Flowgate Capability (AFC
- Flowgate
- Total Flowgate Capability (TFC)
- Transmission Reservation
- Transmission Service Request

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Agree** | **Disagree** | **Comment** |
| ERCOT | | | ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology. |
| **Response:** If ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | | | |
| APPA | | ☑ | This Standard Drafting Team should not try to define terms that have been used by planners, operators, and Reliability Coordinators for many years. The terms Rated System Path (RSP) Method and Network Response (NR) Method have already been defined or described in many white papers for operators and planners. Why is the following an incorrect statement; "The method (RSP, NR, or Flowgate) will be determined by the method that the planners and operators use for that part of the Bulk Electric System." |
| **Response:** There was no consensus on the proposed definitions for Rated System Path and Network Response and the drafting team will not try to include these as defined terms. | | | |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Agree** | **Disagree** | **Comment** |
| BPA | | ☑ | The definition of Network Response Method does not convey any substantive characteristics that describe what it is, or how to distinguish the method from the Rated System Path Method. The definition for Rated System Path likewise is insufficiently described and appears to merely describe a method that relies on a calculation of TTC for one or more paths. Since both methods appear to be based on the same formula (ATC/AFC = TTC/TFC-ETC-TRM-CBM), it is unclear what the substantive distinction is between the two methods.<br><br>The Long-Term AFC/ATC Task Force April 14, 2005 report did not suggest that there were two fundamentally different methodological approaches to determining ATC. BPA recommends that the NERC ATC drafting team defer any efforts to refine the definitions of Rated System Path Method and Network Response Method until the standard requirements for calculating TFC, TRM, CBM and ETC are developed. |
| **Response:** There was no consensus on the proposed definitions for Rated System Path and Network Response and the drafting team will not try to include these as defined terms. | | | |
| KCPL | | ☑ | Available Flowgate Capacity: The definition should end at "Existing Transmission Commitments". If "retail customer service" should be included in ETC, then it should be in the definition and subsequent reliability standards for the development of ETC. |
| **Response:** The drafting team is not going to pursue definitions for 'Available Flowgate Capability' and 'Existing Transmission Commitments.' | | | |
| MISO | | ☑ | The definitions do not include TTC and ATC. All definitions related to this standard should be in a single place (TFC and AFC are defined). The Rated System Path method and the Network Response Method are both approaches for facilitating the processing of Transmission Service Request and need to be measured against similar requirements. |
| **Response:** The ATC data exchange requirements are in the next version of the standards and clarify the difference. There was no consensus on the proposed definitions for Rated System Path and Network Response and the drafting team will not try to include these as defined terms. Note that TTC and ATC are already defined and are in the NERC Glossary of Reliability Terms. | | | |
| Duke Energy | | ☑ | The definitions of Network Response Method and Rated System Path Method are too vague. |
| **Response:** There was no consensus on the proposed definitions for Rated System Path and Network Response and the drafting team will not try to include these as defined terms. | | | |
| Entergy | | ☑ | Definitions of Network Response Method and Rated System Path Method are not clear. It is not clear what is meant by "…customer Demand, generation resources, and the Transmission systems are closely interconnected" in Network Response Method, as they are always closely interconnected. This definition does not reflect that the Transfer Capability is calculated using response of the system or by simulating the impact of flows on the system. The Rated System Path Method appears to be using only the critical path |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Agree** | **Disagree** | **Comment** |
| | | | ratings. It is not clear how critical paths are determined and what ratings are used for those. Since there is no difference in calculation of ATCs by either Network Response Method or Rated System Path Method, there does not seem to be any need for including the definition in this standard. If these definitions are applicable only for TTC calculations, these terms should be defined and included in standard dealing with TTC (FAC-012). If included in FAC-012, these definitions should reflect clearly how calculations are performed under each method. |
| **Response:** There was no consensus on the proposed definitions for Rated System Path and Network Response and the drafting team will not try to include these as defined terms. | | | |
| MRO | | ☑ | a. The definition for AFC and ETC does not specifically refer to market flows. Are these considered a part of ETC or are they not to be included in the calculation of AFC? Please clarify where these are to be dealt with in the calculations. b. There is no specific reference to confirmed or non-confirmed transmission reservations in either AFC or ETC. Are these to be included in ETC? Please clarify the definitions in regard to such reservations. |
| **Response:** The requirements for ETC are embedded in the three standards that include the details for three different methods for calculating ATC (MOD-028, MOD-029 and MOD-030). The drafting team is not going to pursue a definition 'Existing Transmission Commitments.' The revised standards include more specific requirements for constraints in determining ETC and contain much more explicit requirements for determining AFC. | | | |
| Grant County PUD | | ☑ | I have no problems with the definitions themselves. I do stress again to avoid long lists of defined terms, since they make the document more difficult to read, and comprehend. One other point would be that if these terms are used in other standards, they could be defined slightly different causing confusion. |
| **Response:** There wasn't consensus on most of the proposed definitions, and the drafting team eliminated most of these. | | | |
| Progress Energy | | ☑ | The definition of ETC should include the phrase "including retail customer service" and then that parenthetical should be removed from the definition of ATC; Clarification is needed for the Network Response Method and Rated System Path Method to reconcile with the 1995 and 1996 documents. |
| **Response:** Retail customer service is included in Native Load uses. There was no consensus on the proposed definitions for Rated System Path and Network Response and the drafting team will not try to include these as defined terms. | | | |
| Southern | | ☑ | Define network response and rated system path method more implicit (wording and intent) to the methods of ATC and AFC. Look more to the explanations in the 96 documents (pp15). The present definitions for Network Response Method and Rated System Path Method are unclear and do not adequately describe the three methods in the standard. Throughout the document, the three methods are Rated System Path Method, Network Response ATC Method and Network Response AFC Method. The two terms were taken from the 1996 document. Network Response Method that is described in that document appears to reflect the AFC process. A suggestion would be to used the Network |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Agree** | **Disagree** | **Comment** |
| | | | Response Method for the AFC process and the Area Interchange Method (1995 document) for the ATC process. |
| **Response:** There was no consensus on the proposed definitions for Rated System Path and Network Response and the drafting team will not try to include these as defined terms. | | | |
| WECC ATC Team | | ☑ | The Network Response Method definition needs clarity and a stronger description.<br>The NERC Team indicates in Q7 that there is a difference between the Network Response Methodology-ATC and Network Response Methodology-AFC that is not yet apparent. If this is correct, a separate free standing definition would be warranted for each of the methodologies. |
| **Response:** There was no consensus on the proposed definitions for Rated System Path and Network Response and the drafting team will not try to include these as defined terms. | | | |
| SCE&G and SERC ATCWG | | ☑ | Clarification is needed for the Network Response Method and Rated System Path Method to reconcile with the 1995 and 1996 documents. As example, R1 is confusing using the definitions as stated in current draft. NRM has been applied to two separate calculations (FCITC and AFC). In R1, add "not used for AFC" following "Network Response Methodology" in the parenthetical. |
| **Response:** There was no consensus on the proposed definitions for Rated System Path and Network Response and the drafting team will not try to include these as defined terms. | | | |
| ODEC | | ☑ | |
| CAISO<br>IRC<br>ISO-NE<br>SPP | ☑ | | Remaining definitions: AFC, Network Response Method, Rated System Path Method, TFC, Transmission Reservation are OK. |
| **Response:** Many stakeholders disagreed with the proposed definitions for AFC, Network Response Method, Rated System Path Method and | | | |
| MidAmerican | ☑ | | The AFC definition is acceptable, but the equation in R4 does not match the definition. The equation in R4 should read:<br><br>AFC = TFC – TRM – CBM – ETC |
| **Response:** The revised standard that addresses AFC (MOD-030) does not include any formal equations. Here is one of the requirements being proposed in the set of standards to address ATC – the new requirements are much more explicit:<br>The Transmission Service Provider shall calculate Firm AFC by reducing the TFC by the sum of the firm Existing Transmission Commitments (ETCs), the Capacity Benefit Margin (CBM), and the Transmission Reliability Margin (TRM) allocated to the Flowgate. | | | |
| HQT | ☑ | | |
| IESO | ☑ | | |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Agree** | **Disagree** | **Comment** |
| ITC Transco | ☑ | | |
| Manitoba Hydro | ☑ | | |
| FRCC | ☑ | | |
| AECI | ☑ | | |
| APS | ☑ | | |
| NPCC CP9 | ☑ | | |
| NYISO | ☑ | | |

6. The proposed standard assigns all requirements for developing ATC and AFC methodologies and values to the Transmission Service Provider. Do you agree with this? If not, please explain why.

**Summary Consideration:** Most commenters seemed to agree. The group will look at ensuring compliance is measurable, as well as consider overall coordination and review requirements. MOD-001 was revised and the intent of MOD-001 is now distributed between 4 standards – with MOD-001 as an 'umbrella' standard, and each of the other three standards (MOD-028, MOD-029, MOD-030) addressing one of the three methods of determining ATC.

| **Question #6** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | As written the Standard is unclear and could not be audited for compliance. Numerous requirements have been omitted or written so incomplete that it is uncertain what a Transmission Service Provider is to do to provide a accurate ATC/AFC that is consistent with other TSPs. Requirements listed in MOD-001, particularly for flowgate, are the responsibility of the planners and operators for determining transfer capability. Many of the requirements, particularly for Flowgate are rules for determining ETC, not posting ATC values. |
| **Response:** The drafting team recognizes these concerns, and will endeavor to ensure that compliance can be addressed as the compliance elements are written. | | | |
| ERCOT | | ☑ | The transmission service provider seems appropriate, however, there is need for a broader oversight or review to coordinate. Without such an "umbrella" there is likely to be differing values calculated by different transmission service providers for the same parts of the transmission system. |
| **Response:** To improve the accuracy of the values calculated, this standard requires the Transmission Service Provider to share and/or coordinate the data used to determine ATC and AFC with other TSPs and affected entities. However, even with this level of coordination, the calculated values for ATC and AFC can inherently be different between TSPs due to the differing of inputs (i.e. transmission service that is sold). | | | |
| Progress Energy | | ☑ | The standard should assign all requirements for developing ATC to the TSP ; AFC is just an engine. But "YES", the TSP, regardless of the engine and/or inputs it uses, should be responsible for developing its ATC methodology. |
| **Response:** MOD-001 was revised and the intent of MOD-001 is now distributed between 4 standards – with MOD-001 as an 'umbrella' standard, and each of the other three standards (MOD-028, MOD-029, MOD-030) addressing one of the three methods of determining ATC. In MOD-030, there are requirements to convert AFC to ATC. | | | |
| Entergy | ☑ | | Since ATC and AFC calculations are performed for selling the Transmission Service (Capability) to customers based on the Open Access Transmission Tariff which is administered by the Transmission Service Provider, it makes sense to assign requirements for ATC and AFC calculations to Transmission Service Providers. |
| **Response:** Agreed. | | | |
| MISO | ☑ | | The standard is very generic for the ATC methodology/rated system path method. The standard does not provide for transparent and consistent computation of ETC which is the biggest driver in ATC/AFC calculations. To address the Order 890 requirements of consistency and transparency, the standard |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | needs to be methodology neutral. |
| **Response:** MOD-001 was revised and the intent of MOD-001 is now distributed between 4 standards – with MOD-001 as an ‘umbrella’ standard, and each of the other three standards (MOD-028, MOD-029, MOD-030) addressing one of the three methods of determining ATC. In MOD-030, there are requirements to convert AFC to ATC. MOD-029 contains requirements for the Rated System Path method of determining ATC and also includes related requirements for ETC. The modifications are aimed at meeting stakeholder comments as well as the directives in Order 890. | | | |
| FRCC | ☑ | | The B.A. and LSE should have obligations to provide the information in R6 i.e. dispatch order, forecasted loads, etc that are applicable. |
| **Response:** These supporting tasks are at a much lower level than the level envisioned in this set of proposed standards. The revised proposed set of standards for calculating ATC do not contain any requirements for the BA or LSE. | | | |
| Grant County PUD | ☑ | | This is consistent with the Functional Model. |
| **Response:** Agreed. | | | |
| ODEC | ☑ | | Transmission Provider should be calculating the ATC and AFC by following details standards from NERC/NAESB on how to perform this task. |
| **Response:** MOD-001 was revised and the intent of MOD-001 is now distributed between 4 standards – with MOD-001 as an ‘umbrella’ standard, and each of the other three standards (MOD-028, MOD-029, MOD-030) addressing one of the three methods of determining ATC. NAESB is working on associated business practices that include tasks such as posting documents. | | | |
| AECI | ☑ | | |
| APS | ☑ | | |
| BPA | ☑ | | |
| CAISO | ☑ | | |
| Duke Energy | ☑ | | |
| HQT | ☑ | | |
| IESO | ☑ | | |
| IRC | ☑ | | |
| ISO-NE | ☑ | | |
| ITC Transco | ☑ | | |
| KCPL | ☑ | | |
| Manitoba Hydro | ☑ | | |

| Question #6 | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| MidAmerican | ☑ | | |
| MRO | ☑ | | |
| NCMPA | ☑ | | |
| NPCC CP9 | ☑ | | |
| NYISO | ☑ | | |
| Southern | ☑ | | |
| SPP | ☑ | | |
| WECC ATC Team | ☑ | | |

7. In Requirements 1 and 4, the standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). Should the drafting team consider other methodologies? (Note that the difference between the Rated System Path methodology for calculating ATC and the Network Response methodology for calculating ATC use identical equations, but there are distinct differences between these methodologies that will become more clear when the drafting team issues its proposed changes to the standards that address Total Transfer Capability or Transfer Capability.) Please explain.

**Summary Consideration:** The team recognizes that there are questions and concerns regarding this question. MOD-001 was revised and the intent of MOD-001 is now distributed between 4 standards – with MOD-001 as an 'umbrella' standard, and each of the other three standards (MOD-028, MOD-029, MOD-030) addressing one of the three methods of determining ATC. This division of methodologies is supported by the language in FERC Order 693.

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| ERCOT | | | ERCOT does not use these values in its operations. |
| **Response:** Agreed. However, if ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | | | |
| PG&E | | | More detail on each of the methodology is needed for meaningful comment. I look forward to more information. |
| **Response:** Please see the revised set of ATC-related standards. | | | |
| APPA | | ☑ | 1. A Transmission Service Provider (TSP) function will only sell excess transmission capacity and not determine what methodology that is used to plan and operate the BES. How would a TSP come up with a different method when it is the planners and operators that determine a method?<br>2. Requirements 1 and 4 do not address the formula for determining non-firm ATC;<br>3. does not address if TSP is Monthly, Daily, or Hourly in Requirement 1;<br>4. and does not address how many values of Monthly Daily, and Hourly ATC should be posted.<br>5. In addition, Requirement 4 does not address how the TSP will determine an ATC from the AFC calculations? How will these be handled? |
| **Response:** 1. The team recognizes this concern, and revised the standard to clarify that the TSP must 'agree upon' the method with its Planning Coordinator and Reliability Coordinator.<br>2. Please see the revised standards for ATC – they do include requirements to differentiate between calculations for 'firm' and 'non-firm' ATC as proposed. | | | |

| Question #7 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| 3. Please see the revised standards for ATC- the revised standards to provide specificity regarding the frequency for calculating ATC.<br>4. Posting of ATC values is handled by NAESB.<br>5. Please see the proposed standard that addresses AFC (MOD-030) – this standard does include requirements that address converting AFC to ATC. | | | |
| CAISO | | ☑ | We think those are the common used methodologies, we don't know of any others that are widely used.<br><br>However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.<br><br>Hence, we question the need for the qualifying statement – "using a Network Response Methodology" in parentheses, after "calculates AFC" in each of R4, R5 and R6. |
| **Response:** The intent of the AFC approach was to describe how a single request can impact multiple posted ATC values. Since a request made to a TSP using the Rated System Path methodology would only impact one posted ATC value, it does not make sense to associate the AFC with the Rated System Path methodology | | | |
| Entergy | | ☑ | There does not appear to be any difference for ATC calculations for Network Response Method and Rated System Path Method, therefore for the purpose of ATC calculations it does not matter how TTCs are calculated. If the difference will become clear in the TTC calculation method standard, then these definitions and methodologies should be included in that standard (FAC-012) and removed from this standard. There are clearly two methods of Transmission Capability calculations, ATC method and AFC method and only these should be included in the current standard. |
| **Response:** Agree. Please see the revised set of ATC standards – the requirements for calculating ATC using the Network Response Method are in MOD-028 – and the requirements for calculating ATC using the Rated System Path method are in MOD-029. Each of these standards contains much more detail in calculating ATC and no longer use 'formulas.' | | | |
| FRCC | | ☑ | The standard should allow a Transmission Provider flexibility to use different methodologies depending on seam and other factors. |
| **Response:** A TSP should be allowed to use more than one ATC approach so long as the same approach is utilized consistently for all customers on a given POR-POD path for a specific time horizon. This is stated more clearly in the revised MOD-001. | | | |
| Grant County PUD | | ☑ | However, the standard should be written in a way that if there are other methodologies, now or in the future, they could somehow be accomodated. This thought is based on the concept that the new methodology is defensible. |
| **Response:** The inclusion of any methodologies that are not identified in the final set of ATC standards must occur through the NERC standard development process. | | | |
| IRC | | ☑ | We think those are the common used methodologies, we don't know of any others that are widely used.<br><br>However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.<br><br>Hence, we question the need for the qualifying statement – "using a Network Response Methodology" in parentheses, after "calculates AFC" in each of R4, R5 and R6. |
| **Response:** The intent of the AFC approach was to describe how a single request can impact multiple posted ATC values. Since a request made to a TSP using | | | |

| Question #7 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| the Rated System Path methodology would only impact one posted ATC value, it does not make sense to associate the AFC with the Rated System Path methodology | | | |
| ISO-NE | | ☑ | We think those are the common used methodologies, we don't know of any others that are widely used.<br><br>However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.<br><br>Hence, we question the need for the qualifying statement – "using a Network Response Methodology" in parentheses, after "calculates AFC" in each of R4, R5 and R6. |
| **Response:** The intent of the AFC approach was to describe how a single request can impact multiple posted ATC values. Since a request made to a TSP using the Rated System Path methodology would only impact one posted ATC value, it does not make sense to associate the AFC with the Rated System Path methodology | | | |
| Manitoba Hydro | | ☑ | think it is of paramount importance that only one methodology is used within an interconnection (i.e. the east and the west can use different methodologies but within each interconnection should only use one methodology). My reasoning for this is is tied to consistent assumptions. Each transmission privider will develop and study flowgates using a single methodology. If a neighbouring transmission provider is studying inpacts on that flowgate using a different set of assumptions or methodolgy then reliability would be inpacted. |
| **Response:** The drafting team has recognized two fundamentally different approaches to calculating ATC and believes these two approaches can be used in a reliable manner within the same interconnection. | | | |
| NYISO | | ☑ | We think those are the common used methodologies, we don't know of any others that are widely used.<br><br>However, we do not understand why AFC calculation must be tied with the Network Response methodology. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates themselves could become the Rated Paths.<br><br>Hence, we question the need for the qualifying statement – "using a Network Response Methodology" in parentheses, after "calculates AFC" in each of R4, R5 and R6.<br>The NYISO is concerned that the requirements identified in the standard may becoming to much of a 'how' vs. a 'what' needs to be done for reliability. The drafting team may not be able to satisfy all TSP and their associated Market Design requirements. |
| **Response:** The intent of the AFC approach was to describe how a single request can impact multiple posted ATC values. Since a request made to a TSP using the Rated System Path methodology would only impact one posted ATC value, it does not make sense to associate the AFC with the Rated System Path methodology | | | |
| ODEC | | ☑ | These three are enough… It would be preferable to have only one for standardization across the NERC footprint. |
| **Response:** The drafting team has recognized two fundamentally different approaches to calculating ATC and believes these two approaches can be used in a reliable manner within the same interconnection. | | | |
| Southern | | ☑ | 1. As discussed in ETC definition, ETC as currently defined is not applicable to the ATC calculation.<br>2. ETC should be replaced by firm and non-firm interface usage.<br>3. Also, ATC should be expanded into separate firm and non-firm ATC calculations.<br>4. Internal native load serving uses are not a component of ATC. |

| Question #7 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | 5. Non-firm ATC should reflect that CBM (and often TRM) are not deducted and also should reflect the postback of unscheduled service.<br>6. Some discussion of adjustments for redirected service in interface usage amounts should be included.<br>7. Indication of whether TTC values reflect simultaneous or non-simultaneous values should also be included.<br>8. AFC should be expanded into separate firm and non-firm AFC calculations.<br>9. Non-firm AFC should reflect that CBM (and often TRM) are not deducted and also should reflect the postback of unscheduled service.<br>10. The formula seems to indicate TRM and CBM are MW values. Some TPs address TRM by derating TFC values by a percentage, such as 5%. Some discussion of this practice or alternate formulas for AFC for those utilizing this practice should be included. The alternate approach should include discussion of how TFC values are affected for both firm and non-firm AFC.<br>11. The formula does not include how counterflows are treated.<br>12. Since TFC is similar to a facility rating, not a (n-1) transfer analysis, the impacts of counterflows must be considered in calculating AFC and are therefore appropriate in an AFC calculation.<br>13. Similarly, some discussion should be included of how inadvertent flows from neighboring areas (loop flows) are considered.<br>14. An additional formula should be modified will be required to include the calculation of ATC from AFC.<br>15. Some discussion of what rating is used for TFC (static, Rate A, Rate B, ambient adjusted, etc.) is used in which horizons should be included. |
| **Response:** 1,2,6: Please see the detailed requirements relative to ETC in the proposed MOD-028, MOD-029 and MOD-030. The new requirements support the FERC directives relative to ETC.<br>3,5,8,9 :Please see the detailed requirements relative to the calculation of ATC and AFC in MOD-028, MOD-029 and MOD-030. The new requirements are much more explicit than those in the first draft of MOD-001.<br>4: Internal native load is not directly a component of ATC, but should be considered as part of ETC.<br>7: Please review the new set of proposed standards and let us know if you still feel that this distinction is necessary. | | | |
| SPP | | ☑ | We think those are the common used methodologies, we don't know of any others. |
| **Response:** Agree. | | | |
| WECC ATC Team | | ☑ | For purposes of MOD-01, the WECC Team does not believe the standing NERC / NAESB ATC Drafting Team should entertain any additional methodologies. Preclusion at this stage does not foreclose the future use of the NERC SAR process should a more efficacious approach arise from within the industry. |
| **Response:** Agree. | | | |
| BPA | | ☑ | |
| APS | | ☑ | |
| Duke Energy | | ☑ | |
| KCPL | | ☑ | |
| IESO | ☑ | ☑ | We are not suggesting that the SDT consider other methodologies. However, we do not understand why AFC calculation must be tied with the Network Response methodology only. Use of Flowgate, and determining TFC and calculating AFC on the identified Flowgates can be applied to the Rated System Path methodology as well. In this case, the Flowgates |

| Question #7 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | themselves could become the Rated Paths.<br>Hence, we question the need for the qualifying statement – "using a Network Response Methodology" in parentheses, after "calculates AFC" in each of the requirements R4, R5 and R6. |
| **Response:** The intent of the AFC approach was to describe how a single request can impact multiple posted ATC values. Since a request made to a TSP using the Rated System Path methodology would only impact one posted ATC value, it does not make sense to associate the AFC with the Rated System Path methodology | | | |
| MidAmerican | ☑ | ☑ | It should require that each of the three methodologies be standardized such that any provider utilizing that methodology can duplicate the results from the input data. |
| **Response:** It is the intent of the Drafting Team to ensure enough information is provided regarding the ATC calculations that this is possible. | | | |
| HQT | ☑ | | 1. R5, R6, R7 Companion's requirements for Rated system path are not specified<br>2. R1 requires that TTC/TFC be calculate first then ATC/AFC : TTC/TFC - TRM-CBM-ETC.<br>The TSP shall have the possibility to calcualte available Incremental ATC (IATC) ATC/AFC first based on ETC than TTC/TFC should equal: TTC = IATC+ETC.<br>3. R9 TSP methodology shall be consistently tied with the "path" and TSP may use different set of assumptions pending the time frame for which the TTC,ATC, etc are calculated |
| **Response:** 1. The requirements R5, R6 and R7 are not required to perform the ATC calculation associated with the Rated System Path methodology. (Note that the original MOD-001 has now been subdivided and expanded – the requirements for calculating ATC using the Rated System Path method are now in MOD-029)<br>2. Please see the revised set of standards – these contain much more detail on these calculations.<br>3. Please see the revised set of standards - the Rated System Path methodology for calculating ATC is addressed in MOD-029 in much more detail than originally proposed. Each of the three new standards contains its own set of requirements – and there are variations as you proposed. | | | |
| ITC Transco | ☑ | | The drafting team should consider other methodologies if they are aware of any entities using another methodology and achieving reliable results. |
| **Response:** Based on FERC directives, the Drafting Team was given the objective to minimize the number of methodologies utilized in the industry to promote consistency. If there are other methodologies successfully utilized in the industry, those entities are responsible to bring them to the NERC Drafting Team for consideration during this drafting process. | | | |
| MISO | ☑ | | Same comment as previously; to address the Order 890 requirements of consistency and transparency, the standard needs to be methodology neutral. |
| **Response:** The MOD's need to be methodology specific, and more details are included in the revised set of standards. The exchange of data among TSPs should be consistent and is addressed in the revised MOD-001. | | | |
| MRO | ☑ | | Contract Path Methodology should be considered. |
| **Response:** Please review the proposed standard for 'Rated System Path'. | | | |
| Progress Energy | ☑ | | All methodologies that are used to calculate ATC should be included in this standard. |
| **Response:** Based on FERC directives, the Drafting Team was given the objective to minimize the number of methodologies utilized in the industry to promote consistency. If there are other methodologies successfully utilized in the industry, those entities are responsible to bring them to the NERC Drafting Team for consideration during this drafting process. | | | |
| AECI | ☑ | | |

8. In Requirement 2, the Transmission Service Provide that calculates ATC is required to recalculate ATC when there is a change to one of the values used to calculate ATC-TTC, TRM, CBM or ETC. When TTC, TRM, CBM or ETC changes, how much time should the Transmission Service Provider have to perform its recalculation of ATC?

**Summary Consideration:** There was no consensus on this issue. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'.

| Question #8 | |
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| **Commenter** | **Comment** |
| APPA | This will depend on if you are talking about Monthly, Daily, or Hourly ATC. If you are talking about Hourly ATC the change will need to be made quickly; however, if the ETC for Monthly changes the need to repost is not so important since the need for the Transmission capacity is much further into the future. |
| **Response:** Agree. | |
| APS | The Transmission Service Provider should have no more than an hour to perform its recalculation of ATC. In the west, the clock should only start after it is determined that the TTC needs changing. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| BPA | The transmission service provider should recalculate ATC contemporaneously with any formal changes in TTC, TRM or CBM. The transmission provider should recalculate ATC immediately upon any event that changes ETC in the Operating Horizon and scheduling horizon. The transmission provider should recalculate ATC within two business days of any changes in ETC that affect the Operations Planning Horizon or beyond. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| Entergy | Calculation and posting of ATC for Constrained Path is included in FERC Order 889 section 37.6(3)(i)(C)(2) as "The capability posted ……… must be updated when transactions are reserved or service ends or whenever the TTC estimate for the Path changes by more than 10 percent. Calculations and posting of ATC for Unconstrained Paths are included in FERC Order 889 section 37.6(3)(ii)(A) as " ….These postings are to be updated whenever the ATC value changes for more than 20 percent. " Therefore, calculation of ATC values on all paths when any of the components changes may not be required. If the ATC is recalculated and not posted it does not do any good. Timing of Posting on OASIS should determine when the ATC and AFC values should be recalculated. Since these timing requirements will be included in NAESB Business Practice Standard there is no need for a requirement R2 in MOD-001 for recalculation of ATC values. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| ERCOT | ERCOT does not have a transmission service market and does not use this methodology. |
| **Response:** Agreed. However, if ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits | |

| Question #8 | |
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| **Commenter** | **Comment** |
| one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | |
| FRCC | The amount of time needs to correlate with the product and the timeframe effected. For example, an ETC change in future month 8 the length of time to update the posting should be days. If a line trips changing the TTC for the next day then the length of time to update should be hours. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| Grant County PUD | Specifying a time is difficult, since it is arbitrary. If the process is automated, it could be immediately. If it is manual, more time is needed. If extensive study is needed, it could take some time, especially if it has to be coordinated with another TSP. It should be as soon as reasonably practicable. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| HQT | Will depend on the Time Frame. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| IESO | No more than 1 hour. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| SPP | We think one day is reasonable in case TTC, TRM or CBM changes.<br>If ETC changes re-calculation should be done within 1 of 2 hours.<br><br>TTC typically only changes with upgrade of the flow gate element. TRM values change when the TP re-calculates the TRM values, twice a year or something like that. So TTC and TRM don't change on a daily basis, more on a Seasonal Basis. It can take SAS 70 related Change Control Approvals to get the values changed in the AFC databases. Getting approvals can take an hour or more if it is defined as an Emergency Change. After adding the new values to the AFC databases, it can take an hour or more before all Horizons are updated in Oasis Automation. The EMS AFC Calculator has to re-run all hours and days of the Horizons and that takes a little more than an hour. So starting from the time a new TRM or TTC value is submitted to TP, it can take a few hours before it is in Oasis and Oasis Automation. Also in many cases the Transmission owner doesn't immediately inform the TP of an upgrade the minute it happens, most of time a few days later. So it is in general not considered critical to immediately update the ATC and AFC values when TTC or TRM changes. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| IRC<br>ISO-NE | We think one day is reasonable in case of TTC, TRM or CBM changes.<br>If ETC changes, then re-calculation should be done within 1 or 2 hours. |

| **Question #8** | |
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| **Commenter** | **Comment** |
| NYISO<br>CAISO | |
| **Response:** It is not clear why you should differentiate the reason for the change in ATC, but rather that a change in ATC has occurred. The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| KCPL | Recalculation of ATC may be in the OATT agreements and is not needed here. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| Manitoba Hydro | In an automated system, why wouldn't this be immediately (or as soon as the information is loaded into the system that calculates ATC/AFC. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| MidAmerican | The timing requirements of R2 should be the same as the timing requirements of R7. |
| **Response:** In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| MISO | The calculation frequency should be the same regardless of the calculation methodology. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| MRO | Once the TSP is aware that something has changed, then the TSP has to determine what changes in the components are appropriate via analysis which is often times off-line, then changes are perhaps incorporated into an automatic process for ATC postings. From the question it is the MRO's opinion that the Drafting Team is interested in getting a reading on the time required to post a change in ATCs once the amount of component change is determined. The entire process from the time that it is clear that a component needs to be changed to when new ATCs are posted typically takes two weeks. The time once the changes in the components are determined is typically a one day process. It is presumed that the latter time frame is the time frame in which the Drafting Team is interested. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| ODEC | It needs to be a short time, but reasonable to meet for the TSP. I would say 15 minutes or less. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| Progress Energy | For ATC calculations and posting of next-hour up through the next 14 days, the TSP should be given one hour to recalculate it's ATC and then it should post the new value as soon as practicable. For all longer term ATC calculations (e.g. 15 days out and further), ATC calculations and posting should have more time. |
| **Response:** The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on 'changes to inputs'. | |
| Southern | We agree with this requirement for ATC. We do not agree that TTC should be recalculated whenever a parameter |

| Question #8 | |
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| **Commenter** | **Comment** |
| | changes. |
| **Response:** This question is related to timing of recalculation of ATC. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on ‘changes to inputs’. | |
| WECC ATC Team | The WECC Team concurs that ATC should be recalculated anytime there is a change to any of the ATC variables. However, once the ATC is recalculated, the periodicity of posting the ATC is a business practice that should be deferred to NAESB. |
| **Response:** Agree. The frequency of updates should be consistent, regardless of methodology. In the revised MOD-001, the drafting team provided a minimum frequency for recalculating ATC without focusing on ‘changes to inputs’. | |

9. Do agree you with the frequency of exchanging data as specified Requirement 6?

**Summary Consideration:** There was no consensus on the appropriate frequency for exchanging data. One of the goals of this standard is to significantly increase the coordination between all Transmission Service Providers. Sharing data between providers is one of the keys to make this happen. If any transmission provider feels it should have data from one of its neighbors, the neighboring TSP should make all efforts to share this data with a frequency that makes the data useful.
The drafting team modified the data sharing requirement to clarify that the **all** TSPs must share data, not just those TSPs that are using the AFC methodology, but did not include a specific time constraint for this exchange. Additional specificity on timing of the data to be exchanged may be included in future drafts.

| Question #9 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| APS | | | Not applicable. |
| ERCOT | | | ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology. |
| **Response:** If ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | | | |
| Duke Energy | | | Frequency should be as agreed upon or 30 days. |
| **Response:** Exchanging hourly AFC values every 30 days doesn't seem to make much sense. Some data needs to be provided at a more frequent interval. | | | |
| WECC ATC Team | | | The question is specific to entities using the AFC methodology and should be reserved for comment by those entities. |
| **Response:** All entities are encouraged to provide comments that will assist the drafting team in developing this standard. Many entities that don't use an AFC methodology may be impacted by that methodology. | | | |
| BPA | | ☑ | Requirement 6 appears to only apply to a transmission service provider that calculates AFC. BPA declines comment on this provision until such time as the distinction between the various methods becomes more clear. (see response to question #5.) |
| **Response:** All entities are encouraged to provide comments that will assist the drafting team in developing this standard. Many entities that don't use an AFC methodology may be impacted by that methodology. | | | |
| Entergy | | ☑ | A limit of 7 days does not appear real. The Data Exchange should be on an agreed upon schedule as some data like line and generation outages, if exchanged within 7 days may not be of any use for calculations of real time or day ahead ATCs and AFCs. Since the data is exchanged for coordinating |

| Question #9 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | ATCs and AFCs it should be left to the entities that need this information to develop frequency of daa exchange rather than this standard putting some upper limit. In addition, current Requirement 6 applies only to Transmission Service Providers using AFC Method. Data need to be exchanged for ATC calculation also for coordination with the neighboring systems. Several items in Requirement 6 are applicable to ATC calculation such as TTC, ETC etc. This is especially true if a Transmission Provider is using a Network Response Method for calculation of ATC values. |
| **Response:** Your comments are very valid. The requirement has been reworded to include all TSPs that use any method of calculating ATC and the list of data to be exchanged between TSPs is identical.. | | | |
| FRCC | | ☑ | General requirement of (7) calendar days referenced in general requirement R6 is inconsistent with the individual requirements contained in R6.1.-r6.10 which often reference specific time frames example R6.10 says " when revised once per hour" or R6.2 that states " as changes occur." |
| **Response:** Your comments are very valid. The requirement has been reworded to include all TSPs that use any method of calculating ATC and the list of data to be exchanged between TSPs is identical. There was no consensus on how often data needs to be exchanged and the drafting team is trying to get agreement on what data needs to be exchanged before adding more requirements on how often the exchange must take place. | | | |
| ISO-NE | | ☑ | While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (i.e. Before changes, after a change, after seven days from an agreement) is confusing. Is "as agreed upon" acceptable if it is greater than every seven days? |
| **Response:** Your comment is very valid. The reference to 7 days was confusing and has been omitted in the revised standard. The requirement has been reworded to include all TSPs that use any method of calculating ATC and the list of data to be exchanged between TSPs is identical.. | | | |
| MidAmerican | | ☑ | In the Eastern Interconnection, the timing requirements of R6 should match the related timing requirements of the MISO/MAPP/PJM/SPP/TVA SOAs/JOAs. |
| **Response:** The requirement has been reworded to include all TSPs that use any method of calculating ATC and the list of data to be exchanged between TSPs is identical. Please advise us if the revised requirement causes a conflict. | | | |
| MISO | | ☑ | The frequency does not allow for any analysis before the ATC/AFC values are posted to the OASIS. The requirements should be more along the lines of using same ATC/AFC values and providing the same to the neighbouring transmission providers. |
| **Response:** The comment is a very valid. The requirement has been reworded to include all TSPs that use any method of calculating ATC and the list of data to be exchanged between TSPs is identical.. | | | |
| MRO | | ☑ | If the Transmission Service Reservation information can be provided every hour why can not the requirements of R6.5, R6.6, and R6.7 be revised to provide hourly reporting as well? |
| **Response:** The requirements for updating flowgates are now contained in MOD-030. There was no consensus on how often data needs to be exchanged and the drafting team is trying to get agreement on what data needs to be exchanged before adding more requirements on how often the exchange must take place. | | | |
| SCE&G and SERC ATCWG | | ☑ | It is unclear whether data exchange is for forward looking or historical time periods. The requirement for beginning data exchange within 7 days is ambitious. A realistic time frame would be 90 days if it is forward-looking. |

| Question #9 | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| **Response:** The reference to 7 days is confusing and is not contained in the revised standard. There was no consensus on how often data needs to be exchanged and the drafting team is trying to get agreement on what data needs to be exchanged before adding more requirements on how often the exchange must take place. | | | |
| Progress Energy | | ☑ | The intent of R6 is unclear. It is unclear whether data exchange is for forward looking or historical time periods. The requirement for beginning data exchange within 7 days is ambitious. A realistic time frame would be 90 days if it is forward looking. |
| **Response:** The reference to 7 days is confusing and is not contained in the revised standard. There was no consensus on how often data needs to be exchanged and the drafting team is trying to get agreement on what data needs to be exchanged before adding more requirements on how often the exchange must take place. | | | |
| IESO | ☑ | ☑ | We agree with the frequency of exchanging data as specified in Requirement 6. However, we do not agree with the sub-requirement 6.5.<br>Not all TSPs perform load forecasting. They should not be required to provide this information. Beside, load forecast information is already included in the base model a TSP uses in calculating AFCs. This is met by virtue of meeting R6.4. |
| **Response:** The response to this is conditional upon finding out the frequency of update on the base model. Is the load forecast and model used a seasonal, monthly, weekly, or daily update? Updating uses of the transmission system, either with a model or data the goes into the model needs to be done. | | | |
| Southern | ☑ | ☑ | The posting and reposting of data in the OASIS system needs to be taken out of this standard and requirements be put into NAESB standards. Most of this we already do. G&T outages on SDX, dispatch order would be new, power flow model on request, load forecast will be posted on OASIS, Flowgates OK, TFC-our ratings are provided in our cases today, ETC=TSRs is on OASIS] Question: Is R6 dictating duplication of already available information in a different format?<br><br>Also, does 6.8 require 168 models to be created each hour, or just changes in 168 hours of AFC values based upon changes in transmission service requests? Same question for daily. The document refers to OASIS several times. Why specify update intervals here rather than simply referring to FERC OASIS requirements or NAESB business practices? This sets up possible conflict. There is no reliability driver for these particular update frequencies. |
| **Response:** R6 does not address the OASIS system in any manner. R6 is meant to require the sharing of data from the provider to entities that need the data. R6.8 is meant to be AFC values on that provider's flowgates. The requirement to exchange AFC is not in the revised standard for calculating AFC. In the revised set of standards, there is a timing requirement for posting AFC and ATC – and a separate requirement for 'exchanging data' between TSPs. If you are already providing data to a specific location and someone needing that data can get it from that same location, you can agree to use that location as a means to provide the data. The drafting team is working closely with NAESB to ensure that there is no duplication in the final, combined set of reliability standards and business practices. | | | |
| APPA | ☑ | | The need to exchange data will depend upon which component is changing. If the TTC or TFC is changing in the operating time horizon the Reliability Coordinator will need to exchange this information quickly to several Reliability Functions including Transmission Service Providers. Again in the operating time horizons if the ETC, CBM, or TRM changes the Transmission Service Providers |

| Question #9 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | need to recalculate ATC and post this new information quickly to keep the Transmission Customers updated in the quick moving operating horizon. |
| **Response:** The question is not answered in the response, but the drafting team agrees with the comments. | | | |
| CAISO | ☑ | | While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (i.e. Before changes, after a change, after seven days from an agreement) is confusing.  Is "as agreed upon" acceptable if it is greater than every seven days? |
| **Response:** Your comment is very valid.  The reference to 7 days is confusing and is not contained in the revised standard.  There was no consensus on how often data needs to be exchanged and the drafting team is trying to get agreement on what data needs to be exchanged before adding more requirements on how often the exchange must take place. | | | |
| Grant County PUD | ☑ | | As long as this is not overly burdensome on smaller TSPs. |
| **Response:** The standard's requirements are not linked to size. | | | |
| IRC | ☑ | | While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (ie. Before changes, after a change, after seven days from an agreement) is confusing.  Is "as agreed upon" acceptable if it is greater than every seven days? |
| **Response:** Your comment is very valid.  The reference to 7 days is confusing and is not contained in the revised standard.  There was no consensus on how often data needs to be exchanged and the drafting team is trying to get agreement on what data needs to be exchanged before adding more requirements on how often the exchange must take place. | | | |
| NYISO | ☑ | | While the seven days timeframe may be appropriate, the requirement's lack of specificity for the start of this timeframe (i.e. Before changes, after a change, after seven days from an agreement) is confusing.  Is "as agreed upon" acceptable if it is greater than every seven days? |
| **Response:** Your comment is very valid.  The reference to 7 days is confusing and is not contained in the revised standard.  There was no consensus on how often data needs to be exchanged and the drafting team is trying to get agreement on what data needs to be exchanged before adding more requirements on how often the exchange must take place. | | | |
| SPP | ☑ | | The requirement's are very general and don't specify data exchange before changes, after a change, after seven days from an agreement.  It is not clear if "as agreed upon" is acceptable if it is greater than every seven days. |
| **Response:** The reference to 7 days is confusing and is not contained in the revised standard.  There was no consensus on how often data needs to be exchanged and the drafting team is trying to get agreement on what data needs to be exchanged before adding more requirements on how often the exchange must take place. | | | |
| AECI | ☑ | | |
| HQT | ☑ | | |
| ITC Transco | ☑ | | |
| KCPL | ☑ | | |
| Manitoba Hydro | ☑ | | |

| Question #9 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| ODEC | ☑ | | |

10. Requirement 9 indicates that the Transmission Service Provider shall have and consistently use only one methodology for the Transmission Service Provider's entire system in which the ATC or AFC are calculated (Rated System Path — ATC, Network Response — ATC and Network Response — AFC, methodologies). If choosing just one of these methods is not sufficient for your system, please explain why.

**Summary Consideration:** The Standards Drafting Team (SDT) has reconsidered the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001 posting and revised the requirement. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses but must have agreement on the method or methods with its Planning Coordinator and Reliability Coordinator.

| Question #10 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | This Standard is written to make the industry believe that only one ATC will be calculated for each Transmission Service Provider. In reality, the TSP will post several ATCs; one ATC for each path or network the TSP is marketing transmission capacity. Each individual path or network will only use one method, but a TSP's planners may use different methods to plan and operate different paths in their system. MISO and PJM are entities that use two methods to market transmission capacity in its system. They only uses AFC at the borders or seams of their system to determine how much transmission capacity is available at their seams, while they use LMP to determine how much transmission capacity is available on their interior system. BPA will use flowgates to determine how much ATC is available to its Transmission Customer on the interior of their system, while BPA uses Transfer Path on its seams to determine how much transmission capacity is available to Transmission Customers exterior to their system. |
| **Response:** The standard was revised to clarify that each TSP calculates ATC for each constrained path or AFC for each constrained flowgate/cutplane. TSPs will be permitted to use as many of the proposed methods as the TSP chooses, however, the TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| BPA | | ☑ | The substantive differences between the three aforementioned methods are not yet clear. However, if multiple methods are determined to be valid and acceptable approaches to calculating ATC/AFC, then the transmission provider should be able to employ multiple methods for calculating ATC/AFC on different parts of the transmission system, provided the various methods are applied consistently and are transparent. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, the TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| CAISO | ☑ | | Comments: We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology as long as any methodology used is used consistently with transparency. |

| Question #10 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | *E.g. - CAISO currently uses one method on its ties (rated path)to other TSPs and one method for internal (network response). Additionally, for ties if adjacent TSPs use differing methodologies, the rating would not agree, so are we looking at a situation where one methodology may have to be used for each interconnection?*<br><br>*The CAISO agrees with the WECC MIC MIS ATC Task Force that this requirement should be eliminated or the word sole removed.* |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| Cargill | | | No comment. |
| Duke Energy | | | One methodology is sufficient for Duke Energy. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| Entergy | | | Only one method for calculation of ATC or AFC should be used for each system so that there is consistency between the method used for approving transmission service requests and for planning and operation of the system as required in R 11.2. In case more than one method is used it will be difficult to make these methods consistent. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| ERCOT | | | ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology. |
| **Response:** If ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process. | | | |

| Question #10 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | | | |
| FRCC | ☑ | | ifferent method are needed to address seams issues between areas that select different methodologies, different methods may be applicable to different interfaces etc. The transmission provider should have the flexibility to select the appropriate method. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| Grant County PUD | | ☑ | Its hard to answer this question without more detail to the ATC calculations. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| HQT | | ☑ | Methodology choice shall be solely based on the system topology and the path requirements. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used.. | | | |
| IESO | ☑ | ☑ | See comments under Q7 on Rated Path Methodology – AFC (not included in the 3 methods). |
| **Response:** See the response to your comments on Question 7. | | | |
| IRC | ☑ | | We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology.<br><br>*E.g. - CAISO currently uses one method on its ties (rated path)to other TSPs and one method for internal (network response). Additionally, for ties if adjacent TSPs use differing methodologies, the rating would not agree, so are we looking* |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |

| Question #10 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| ISO-NE | ☑ | | We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| KCPL | | ☑ | |
| Manitoba Hydro | | | Requirement 9 should be interconnection wide. TSPs do not only calculate ATC on their own systems, they calculate inpacts on a set of flowgates on neighbouring systems. Using a differing methodology would needless impact reliability on those systems. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| MidAmerican | | ☑ | A single methodology should be required not only within each TSP's system, but across a larger footprint, such as an RRO. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| MISO | | | If the questions is one method only for one TP, the answer is no. Due to contract obligations between transmission providers, there is a need to maitain a few contract paths while maintaining Network response method for AFC/ATC calculations. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| MRO | | | Transmission Service Provider may use contract Path methodology in addition to one of the methods provided in the proposed NERC standard. |
| **Response:** If MRO uses a method not captured in this proposed standard, please explain such method to the SDT. | | | |
| NYISO | ☑ | | We question why the SDT requires this single methodology. The SDT should provide an explanation of the reliability problem(s) associated with applying more than one methodology. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one | | | |

| Question #10 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| ATC/AFC method in the original MOD-001. | | | |
| Progress Energy | | | One methodology should be used for the TSP's system. Change "its sole" to "a single" or to "one". Also, the standard should have only one requirement that defines the when and where of ATC methodology ; If you want the same process to be applied across the TSP's whole system and across all time horizons then say that plainly in one requirement instead of splitting the where and when between R9 and R11. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| SCE&G and SERC ATCWG | | | Change "its sole" to "a single" or to "one." The statement in the question above is clear — the language of the requirement was not as clearly stated. |
| **Response:** The Standards Drafting Team (SDT) has reconsidered the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001 posting and revised the requirement. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there will be a requirement that each TSP choose one method for each path/flowgate/cutplane. | | | |
| Southern | | | One methodology is sufficient. For ATC, although there mat be situations where multiple approaches are appropriate to address radial vs. interdependent portions of a system. Also, flexibility may be required in calculating TTC. For example posting non-simultaneous values on radial interfaces and simultaneous values on interdependent paths. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| SPP | ☑ | | We convert AFC to ATC numbers on OASIS, however we start off from AFC numbers that are calculated using one and same methodology. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| WECC ATC Team | | | This requirement is unnecessary and should be deleted. If the NERC team will not delete the Requirement, at minimum the word "sole" must be deleted from the Requirement.<br>If, for example, a TSP has operational needs that dictate the use of the AFC Methodology for paths within its network and the Rated System Path for interfaces with its neighbors, either of these |

| Question #10 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | methodologies is allowed under MOD-01. So long as the TSP consistently and transparently applies any of the NERC approved methodologies to it facilities and communicates that application to all appropriate entities, this approach should be allowed as it has met FERC's core purposes without disrupting operations.<br>In contrast, this constrictive approach over reaches the FERC mandate of consistency and transparency, increases the potential for seams between interchanges and otherwise imposes a burden to alter operations where no remedy is needed.<br>In support of the WECC Team's position:<br>FERC found in Order 890 that "the potential for undue discrimination stems from two main sources: (1) variability in the calculation of the components that are used to determine ATC and (2) the lack of a detailed description of the ATC calculation methodology and the underlying assumptions used by the transmission provider." P. 209. Neither of these concerns is at issue should a TSP use more than one NERC authorized methodology.<br>Further, FERC found that so long as "all of the ATC components and certain data inputs and assumptions are consistent, the three ATC calculation methodologies being finalized by NERC through the reliability standards development process will produce predictable and sufficiently accurate, consistent, equivalent, and replicable results. It is therefore not necessary to require a single industry-wide ATC calculation methodology. *The Commission instead concludes that use of the ATC calculation methodologies included in reliability standards currently being developed by NERC is acceptable."* P. 210. |
| **Response:** The Standards Drafting Team (SDT) has removed the requirement that each Transmission Service Provider (TSP) use only one ATC/AFC method in the original MOD-001. While one methodology may be sufficient for a TSP, limiting all TSPs to use of only one method for their systems may hinder reliability. Therefore, TSPs will be permitted to use as many of the proposed methods as the TSP chooses; however, there is a requirement that each TSP must have agreement with its Planning Coordinator and Reliability Coordinator on which method or methods will be used. | | | |
| AECI | ☑ | | |
| APS | ☑ | | |

11. Do you think that Requirement 13 in this proposed standard is necessary?

R13. If the Transmission Service Provider approves a Transmission Service Request using a value other than and less than its value for ATC or AFC, then the Transmission Service Provider shall identify how it calculated the lesser value.

**Summary Consideration:** The drafting team has removed this requirement, as Order 890 seems to already address the issue.

<table>
<tr><th colspan="4">Question #11</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>ERCOT</td><td></td><td></td><td>ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology.</td></tr>
<tr><td colspan="4">Response: If ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration.</td></tr>
<tr><td>APS</td><td></td><td></td><td>Requirement 13 needs clarification, not sure if agree or disagree.</td></tr>
<tr><td colspan="4">Response: The drafting team has removed this requirement, as Order 890 seems to already address the issue.</td></tr>
<tr><td>Manitoba Hydro</td><td></td><td></td><td>It is hard to say as requirement 13 seems unclear.</td></tr>
<tr><td colspan="4">Response: The drafting team has removed this requirement, as Order 890 seems to already address the issue.</td></tr>
<tr><td>WECC ATC Team</td><td></td><td></td><td>The WECC Team would like an example as to why the NERC Team believes this Requirement is necessary.<br><br>The WECC Team believes that if ATC is posted on OASIS, the entire posted amount must be made available for purchase. For example, if an entity requests 100 MW of legitimately posted ATC and the TSP refuses the 100 MW request but grants 80 MW instead, that TSP must provide to the requesting entity a full and written explanation of why the full 100 MWs of posted ATC were not made available.</td></tr>
<tr><td colspan="4">Response: The drafting team has removed this requirement, as Order 890 seems to already address the issue.</td></tr>
<tr><td>APPA</td><td></td><td>☑</td><td>It is not necessary in this Standard. It will be necessary to explain difference in one of the Standards that spell out the rules for TTC, ETC, CBM or TRM. This is part of the posted assumptions that is</td></tr>
</table>

| Question #11 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | necessary for the Transmission Service Provider to post when showing the values of the components that was used to calculate the number for ATC. MOD-001 is only for the rule of calculating ATC, i.e. maximum time between calculations and rules for recalculations; and posting ATC values and posting values and assumptions for the components. Rules for the components are in other standards. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| IRC<br>CAISO<br>ISO-NE | | ☑ | Approving a request with insufficient AFC might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting a Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is insufficient. This is a common practice and should not have to be documented (justified) after the fact.<br><br>It might happen also if a re-dispatch agreement is accepted by a TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by the TP.<br>Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue should be addressed in the Business Practice. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| BPA | | ☑ | BPA does not understand requirement 13 as written. A transmission provider would normally approve a transmission request if transfer capability required by the request is LESS than the value of ATC available. If the transmission provider approves a request using a value for ATC lower than posted ATC, then the transmission provider should not have to identify or explain its actions. On the other hand, it would make sense to require an explanation if a transmission provider approves a transmission request using a value for ATC that is HIGHER than the value of ATC that is posted. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| Duke Energy | | ☑ | Delete Requirement 13. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| ITC Transco | | ☑ | The requirement is curious. If a service request is approved, who cares if the Service Provider used an ATC/AFC lower than its posted ATC/AFC? I'd be more concerned about a TSR that was rejected because of a lower ATC/AFC, and would want to know how the TSP calculated the lesser value. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| Grant County PUD | | ☑ | No one would have an issue if the Transmission Service Requests are approved. When they are denied justification needs to be made. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |

| Question #11 | | | |
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| Commenter | Yes | No | Comment |
| | | | |
| IESO | | ☑ | Requirement 13 is not required. Approving a service request at a value less than the ATC or AFC is a commercial issue, which does not affect reliability. This issue can be addressed in the Business Practice. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| MISO | | ☑ | This requires policing the tags after the fact, and really has nothing to do with the calculation of ATC/AFC. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| Southern | | ☑ | This was put in here to cover the AFC's AFTFC (?). If this requirement stays in the standard, a suggested rewording is needed. A value "less than" automatically implies a value "other than." The requirement states, "If the TSP approves a TSR...." What if the TSP denies a TSR? This reads like a policy, not a reliability requirement. TSPs already have requirements under the OATT to provide justifications from approving/denying service. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| SPP | | ☑ | It might happen for next hour Non-Firm if available flow gate capacity in real time justifies accepting Non-Firm request, while Non-Firm AFC (that still has some unused Reservations included in end-result) is un-sufficient. This is a common practice and should not have to be documented (justified) after fact.<br><br>It might happen also if a re-dispatch agreement is accepted by TP that requires a Transmission Customer to re-dispatch a certain amount to cover for the negative AFC created on flow gate by accepting Reservation. This is documented by TP. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| Progress Energy | | ☑ | |
| Entergy | ☑ | | Transmission Service Provider may allocate capability of transmission element to different users based on their ownership interest and any other agreements. This requirement allows use of different ATC or AFC values based on such arrangements. However, it does not have to be limited to only lesser of the calculated value used for approving Transmission Service Request. In case a Transmission Service Provider is using higher than the calculated value (in some emergency cases, TP may use emergency rating of limiting line/equipment which may result in higher than the normal calculated ATC value), it may be putting the reliability of the system at risk. Therefore, the Transmission Service Provider should identify how it determines ATC values for approving Transmission Service Requests if those are different from the calculated values, whether higher or lesser than the calculated value. |

| Question #11 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| FRCC | ☑ | | There is a strong reliability need for this. It is believed that the word " posted" needs to be inserted in front of the word value in the statement " other than and less than its value" i.e. the statement should read " other than and less than its posted value." |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| KCPL | ☑ | | Please consider changing "identify how it calculated" to "provide the basis for calculating" in the R13 Reliability Standard. I think it is more important to know why the value changed rather than how the value changed. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| MidAmerican | ☑ | | The phrasing of R13 should be clarified. As currently drafted, it reads:<br><br>If the Transmission Service Provider approves a Transmission Service Request using a value other than and less than its value for ATC or AFC, then the Transmission Service Provider shall identify how it calculated the lesser value.<br><br>MidAmerican believes this is intended to mean, and should be clarified to say:<br><br>If the Transmission Service Provider denies a Transmission Service Request for less than its value for ATC or AFC (or for less than its share of ATC or AFC on reciprocal coordinated flowgates), then the Transmission Service Provider shall identify why the service was denied. This calculation methodology should also be posted. |
| **Response:** The drafting team has removed this requirement, as Order 890 seems to already address the issue. | | | |
| AECI | ☑ | | |
| HQT | ☑ | | |
| MRO | ☑ | | |
| NCMPA | ☑ | | |

12. Do you agree with the other proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

**Summary Consideration**: There were many suggestions to modify the requirements in MOD-001. MOD-001 was revised and the intent of MOD-001 is now distributed between 4 standards – with MOD-001 as an 'umbrella' standard, and each of the other three standards (MOD-028, MOD-029, MOD-030) addressing one of the three methods of determining ATC. Each of the three standards that addresses one of the methods of determining ATC also includes related requirements for TTC (or TFC) and ETC.

Many stakeholders indicated that R14 should be removed and the drafting team did remove this requirement.

| Question #12 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | Many of the requirements listed in MOD-001 are requirements needed in the Standards that set the rules for TTC, TFC, CBM, TRM, and ETC. The characteristic of each component will be made available to the industry if the Standards for the components are written properly. If MOD-001 is written in a manner that requires those characteristic to be provided to the TSP and require the TSP the post characteristics the SDT will meet its obligations.<br><br>R14 should be eliminated. Requiring the same ultimate source and ultimate sink on the Transmission Service Request and the Interchange Transaction Tag will harm commercial use of transmission service. It will force transmission users to redirect transmission service on OASIS every time a source or sink changes, even within the same control areas, while providing little, if any, benefit for reliability. If the drafting team feels this requirement is still needed, it should be passed to NAESB for inclusion as a business practice. |
| **Response:** General: The drafting team agrees.<br>R14: The drafting team removed R14. Note that Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so eventually we will need to add a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). | | | |
| APS | | ☑ | The requirements in R11.2, R11.3, R11.4, R11.5 and R12 do not apply to entities that use the Rated System Path method and should not apply to their ATC calculations. For those that use the Rated System Path method these requirments should apply to the TTC calculations. |
| **Response:** The drafting team agrees that these requirements do not apply to ATC calculations for Rated System Path method. Please see the revised set of standards – the requirements for the Rated System Path method are now contained in MOD-029. | | | |
| BPA | | ☑ | See BPA's response to question 19. |
| **Response:** See drafting team response to Q19. | | | |
| CAISO | ☑ | ☑ | R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation |

| Question #12 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| ISO-NE<br>IRC<br>NYISO | | | works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study→refused).<br>R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is the intension then we agree.<br><br>R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations? TP's typically exchange Net Interchange based on Schedules and sometimes reservations. However that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.<br><br>R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.<br><br>R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. The Receiving Entity could update the AFC data on an hourly basis. If the Sending Entity doesn't update the data on an hourly basis, it is not effective.<br><br>R11.2 The term "same criteria" is too general, it should be more specific.<br><br>R11.4 The term "Identify contingencies" is too general. It is unclear whether this refer to outages or the contingency elements of flow gates.<br>R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology<br>Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:<br>"Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC"<br>Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard.<br>R14 Over stringent, particularly if AFCs are not calculated to the level or scope of granularity. |
| **Response:**<br>R6.8.1. The requirement is to recalculate and update the AFC once per hour for the rolling 168 hours with updated information.<br>R6.8.2 and R6.8.3. The requirements are to recalculate the different products at specific frequency. Although the frequency is the same, the products are not and may be subject to different requirements for determining TRM, CBM, or ETC. | | | |

| Question #12 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| R6.9: The revised standard does not list ETC as one of the types of data that must be exchanged between TSPs.<br>R6.10: The requirement to exchange transmission service reservation information remains in the revised standard, but the timing element of the original requirement (to provide this once per hour when revised) has been removed<br>R7: The standard was revised and no longer includes specific timing requirements for using the updated data.<br>R11 This requirement was modified and is now addressed more specifically in each of the new standards that identifies the requirements for one of the three ATC calculation methodologies (MOD-028, MOD-029, MOD-030). Please see the proposed standards.<br>R12: The revised MOD-001 requires the TSP to develop a document called "Available Transfer Capability Implementation Document" and this document must contain the names of the TSPs with which the TSP exchanges data for use in determining ATC.<br>R14: The drafting team removed R14. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice. | | | |
| SPP | | ☑ | R6.8.1 We are not re-sinking 7 days of hourly values every hour, however the way Oasis Automation works it updates AFC with every Reservation that is submitted and with every Reservations that changes status. (for example Study refused).<br><br>R6.8.3 and R6.8.2 is same, if you have daily AFC for 30 days, you automatically have weeklies for 4 weeks, however not weekly value but daily values to represent the AFC of the 4 weeks. If that is intension we are OK.<br><br>R6.9 Not sure what ETC is intended to be included in R6.9, Gen to Load ETC only or also ETC as result of Reservations. TP's typically exchange Net Interchange based on Schedules and sometimes Reservations , however that assumes that all Reservations will be scheduled. It doesn't reflect directional ETC. A combination of ETC for a Gen to Load situation and the Reservations as referenced in R6.10 will result in the "true" ETC of the system. It can not be provided in an initial Power Flow Model.<br><br>R6.10 We don't think the "once per hour" should apply to all types of Reservations such as Weekly, Monthly and Yearly. It should be based on term of Reservation.<br><br>R7 This requirement might have to be split up in a requirement for the Sending Entity and a requirement for the Receiving Entity. We (receiving Entity) update the AFC data on an hourly basis however if the Sending Entity doesn't update the data on an hourly basis, it is not effective.<br><br>R11.2 "same criteria" is to general, should be more specific.<br><br>R11.4 "Identify contingencies" is to general. Does this refer to outages or the contingency elements of flow gates. |

| Question #12 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | R14 Over stringent, particular if AFC aren't calculated to the level or scope of granularity. |
| **Response:** R6.8: The requirement is to recalculate and update the AFC once per hour for the rolling 168 hours with updated information.<br>R6.8.2 and R6.8.3. The requirements are to recalculate the different products at specific frequency. Although the frequency is the same, the products are not and may be subject to different requirements for determining TRM, CBM, or ETC.<br>R6.9: The revised standard does not list ETC as one of the types of data that must be exchanged between TSPs.<br><br>R6.10: The requirement to exchange transmission service reservation information remains in the revised standard, but the timing element of the original requirement (to provide this once per hour when revised) has been removed<br>R7: The standard was revised and no longer includes specific timing requirements for using the updated data.<br><br>R11.2: This requirement was modified and is now addressed more specifically in each of the new standards that identifies the requirements for one of the three ATC calculation methodologies (MOD-028, MOD-029, MOD-030). Please see the proposed standards.<br>R14: The drafting team removed R14. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice. | | | |
| HQT | | ☑ | Refer to 7<br><br>R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology<br><br>Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:<br><br>•"Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC"<br>Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard. |
| **Response:** R12: The revised MOD-001 requires the TSP to develop a document called "Available Transfer Capability Implementation Document" and this document must contain the names of the TSPs with which the TSP exchanges data for use in determining ATC.<br>Note that the latest versions of the ATC-related standards include requirements for calculation of TTC within each of the three standards that addresses one of the methods of calculating ATC. | | | |
| Cargill | | ☑ | We disagree with R14, which would require a Transmission Service Provider to require Transmission Customers to provide ultimate source and ultimate sink on Transmission Service Requests and further would require that Transmission Customers must use the same source and sink on Interchange Transaction Tags. Our reasons for not supporting this requirement are several, based on our belief that the requirement (1) is impractical under well-established trading and scheduling |

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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | practices, (2) has not been shown to be necessary to the reliability of the North American bulk electric system, (3) is not consistent with the Market Interface Principles, which are an integral part of NERC's Reliability Standards Development Procedure and (4) conflicts with Order 890. Further, it is not apparent from the records of the draft team's development process that due consideration was given to whether the source/sink requirement adheres to NERC's Reliability and Market Interface Principles.<br><br>The source/sink requirement is incompatible with the market's trading and scheduling practices. Forward hedging is commonly transacted at Hubs, with the product defined as an "into-HUB," (e.g., into-Entergy). A supplier who delivers energy to an "into-Hub" sale cannot foresee where the buyer will ultimately sink the energy. That supplier may need to purchase transmission to the Hub's interface, but cannot know in advance what sink to input in a Transmission Service Request on an upstream system. Likewise, the buyer does not know the source until the time of day-ahead scheduling, and, therefore, cannot plan his transmission purchases to coordinate with his into-Hub energy purchase. The seller may choose to deliver the "into-HUB" energy at different interfaces day to day.<br><br>When scheduling energy flows between regions, the timelines for notifying counterparties of sources/sinks may not be consistent. Though a Purchasing-Selling Entity may learn by 10:00 AM where his purchase is being generated for the next day, he may not know until 11:00 AM where that energy is sinking. The party responsible for transmission in the upstream path may have to submit a Transmission Service Request, due to a transmission provider's timing requirements, before the downstream must declare a sink. So transmission providers' timing requirements may not coincide with scheduling and tagging timelines. Further, characteristics of today's organized electricity markets are not compatible with the proposed source/sink requirement.<br><br>When energy is sourced from an organized market (i.e./ LMP system), the actual generating source cannot be identified, as economic dispatch determines generation levels on 5-minute intervals. Thus, for a transaction tagged with a source in an LMP system, the Transmission Service Request and Interchange Transaction Tag may never match. Similarly, in the WECC when a Mid-C product is purchased and taken to delivery, it could be generated at any of numerous hydro-generation facilities, all included in the definition of the Mid-C energy product. The proposed source/sink requirement would put certain market participants at a disadvantage. A Purchasing-Selling Entity who intends to buy transmission to move purchased energy from a Hub to a customer who will transmit the energy downstream beyond the Hub is at the greatest disadvantage with a source/sink requirement. Such a Purchasing-Selling Entity, without known generation or load, may be ignorant of both the source and the sink until the time of scheduling. It is important that the proposed standard is incompatible with trading and scheduling practices. The following is taken from NERC's Reliability Standards Development Procedure: "While NERC reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets." |

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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | The MOD-001-1 drafting team recognizes at least two distinct methods for ATC calculations, the Rated System Path Methodology and the Network Response Methodology. The addition of the source/sink requirement in R14, however, seems to ignore the key difference in the two methods. The Rated Path method looks at the capability of the direct wires between two points, and those points are not necessarily the source or the sink. The draft team's records do not disclose claims that the lack of the proposed source/sink requirement has degraded reliability in those systems where the Rated System Path method is employed. Apparently, source/sink requirements such as proposed in R14 are not necessary to the reliability of the North American Bulk Electric system for those areas using the Rated System Path method. In fact, it is documented in the draft team's working papers that source/sink modeling identification is "not relevant for Rated System Path Method for ATC Modeling." (See draft team's document titled NOPRitems.XLS at http://www.nerc.com/~filez/standards/MOD-V0-Revision-RF.html, dated 7/19/06.) The reason for the subsequent addition of the source/sink requirement to the proposed standard cannot be determined from the draft team's records.<br><br>The impetus for the development and revision of MOD-001-1 was the Final Report of the Long-Term AFC/ATC Task Force. In that report, in the section titled "Source and Sink Points – Calculation Process for AFC/ATC," is the following statement: "The task force suggests that the sources and sinks (injections and withdrawals) used in the calculation of AFC/ATC and the evaluation of transmission service requests should replicate the anticipated use of service when utilized." (Emphasis added.) This statement assumes that requiring source/sink information with a Transmission Service Request and requiring that information to match the Interchange Transaction Tag is not necessary. The next sentence in the report states, "It is important that Transmission Service Providers have business practices outlining when they will allow confirmed transmission reservations to be used in a manner that is not equivalent to how the request for the service was evaluated." Once again, it is granted that source/sink information is not required to match from reservation to tag. And Appendix B of the report states the case even more plainly: "Source and sink points … do not necessarily correspond to the source or sink fields on a transmission reservation, but are constructs that mimic the expected actual change in generation dispatch that would be used to affect that power transfer in real-time."<br><br>Further practical considerations show that the R14 source/sink requirement is not necessary to the reliability of the bulk electric system. For instance, Southwest Power Pool (SPP) employs an "electrical equivalent" concept. According to SPP's Business Practices an exception is allowed when the source/sink of a reservation does not match the source/sink of the tag, so long as the source/sink on the reservation is considered electrically equivalent to the source/sink on the tag. SPP also allows an exception when a customer combines two SPP reservations on the same tag, so long as one reservation has the correct source/sink (or electrical equivalent) and the PORs and PODs are contiguous, such a scheduled reservation/tag is valid. (See 4.3 of SPP's Open Access Transmission Tariff Business Practices.) Additionally, consider schedules that flow across DC ties. There is no |

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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | need, for the purposes of calculating ATC, for transmission providers in the WECC to know where in the Eastern Interconnect a transaction flowing west to east on one of the DC ties is sinking. Likewise, for an energy schedule sourced in ERCOT to a sink in SERC, there is no need for the transmission providers in ERCOT to know the ultimate sink. And no need for the transmission providers in the Eastern Interconnect to know the ultimate source. Source/sink information matching from reservation to tag is not necessary to reliability in these cases.<br><br>The proposed source/sink requirement conflicts with NERC's Reliability Standards Development Procedure, which includes two sets of guiding principles, Reliability Principles and Market Interface Principles. "Consideration of the market interface principles is intended to ensure that reliability standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets." Market Interface Principle 2 states, "An Organization Standard shall not give any market participant an unfair competitive advantage." As mentioned earlier, market participants without known generation resources or load obligations can be put at a definite disadvantage with the proposed source/sink requirement. Market Interface Principle 3 states, "An Organization Standard shall neither mandate nor prohibit any specific market structure." The indirect result of R14 would be to so inhibit markets operated with the Rated System Path Methodology so as to essentially prohibit the prevailing market structure operating where that method is employed. Transmission providers and customers would be forced to transact differently, potentially disrupting long-established and efficient markets. Most importantly, Market Interface Principle 4 states, "An Organization Standard shall not preclude market solutions to achieving compliance with that standard." The title of the standard at issue is ATC and AFC Calculation Methodologies. Yet no explanation can be found in the draft team's records as to how the source/sink requirement in R14 will improve ATC calculations. In reviewing the records of the drafting team, no examples can be found showing that the lack of the source/sink requirement causes degraded reliability. In fact, markets that do not require that ultimate source/sink be provided on a reservation and then match on an Interchange Transaction Tag have obviously determined and implemented solutions to calculating ATC, without such a requirement. The record of the drafting team simply does not provide evidence to the contrary.<br><br>Finally, in reviewing FERC's Order 890, it is apparent that R14's source/sink requirement is inconsistent with established protocols for transmission service reservations. At paragraph 297 of Order 890 the Commission states, "Regarding transmission reservations modeling, we direct public utilities, working through NERC, to develop requirements in reliability standard MOD-001 that specify (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations." Obviously, it is understood that not only existing reservations may not have provided source/sink information, but also, by distinguishing existing reservations, FERC has assumed that future transmission service requests may not provide source/sink information. Indeed the definition of Transmission Service |

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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Reservation proposed in the MOD-001-0 standard references Point of Receipt and Point of Delivery, but not source and sink (see 2. at page 4 of this document.)<br><br>In summary, the proposed source/sink requirement is inconsistent with established trading and scheduling protocols, is not necessary to the reliability of the bulk electric system, conflicts with the principles established to guide the development of reliability standards and is inconsistent with FERC Order 890. For the reasons stated herein, we disagree with the proposed source/sink requirement in MOD-001-1. Cargill |
| **Response:** R14: The drafting team removed R14 from MOD-001. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice. | | | |
| Duke Energy | | ☑ | As written with the requirement to provide ultimate source and ultimate sink, R14 should only apply to reservations and tags on systems that calculate AFC. In general, on systems that calculate ATC or AFC, source and sink granularity on the reservation must be sufficient to allow adequate assessment of the impact on the capacity offering (ATC or AFC). Source and sink granularity on the e-tag must be sufficient to allow adequate assessment of the e-tag's impact on the transmission system. The Point of Receipt (POR) and the Point of Delivery (POD) must be the same on the reservation and the e-tag. If the source or sink on the e-tag is different from the source and sink on the reservation and the impact is substantially different from the expected impact of the reservation, the TP may deny or curtail the e-tag. |
| **Response:** R14: The drafting team removed R14 from MOD-001. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice. | | | |
| Entergy | | ☑ | (R3.) There is no need to include ATC and TTC values to be provided when requested within 7 days as these are expected to be posted on OASIS and be available per OATT requirement.<br>(R4.) The equation assumes that the TRM, CBM and ETC are for each path that has a Distribution Factor factor to each flowgate. Therefore, the language in the standard should be changed to include "respective" before the Distribution Factor for TRM and CBM. In addition, the definition of Distribution Factor included in the NERC Standard Booklet "The portion of Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)" can only be used if the TRM, CBM and ETC are allocated on each Interchange Transaction which is from control area to control area. If the TRM, CBM and ETC standards do not require such allocation, the formula will be invalid.<br>(R5.1) This requirement should also be applicable to ATC calculations if Transmission Service Provider uses impact on interface differently for the Firm and Non-Firm reservation. At a minimum Transmission Service Provider should be required to include method of adjusting the ATCs for Firm |

| Question #12 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | and Non-Firm Reservations for transparency purposes.<br>(R5.2) Comment similar to that for R5.1 applies to this requirement as this requirement should be applicable to ATC calculation.<br>(R 5.3) This requirement is poorly written as it is not clear what is required to be on OASIS, Is assumptions used for base case and transfer generation dispatch for both external and internal system need to be on OASIS? If so, it does not make sense.<br>(R6.3) The monitoring of the requirement of exchanging generation dispatch order that is updated at least prior to each peak load season or the generation participation factors of all units on an affected Balancing Authority basis that is updated as required by changes in the status of the unit will be difficult as these are inconsistent. The participation factors theoretically will change any time the generator status changes and will have to be recalculated and shared with all entities. Transmission Service Providers should be required to exchange participation factors when updated and at a minimum prior to each peak load season rather than required to calculate when generator status changes.<br>(R6.8) This requirement is applicable only to AFC calculations as AFC values for different periods need to be updated at certain interval. First this requirement is based on FERC Order 889 and is of commercial nature, therefore, it should be included in NAESB business practices. Secondly, this requirement is also applilcable to ATC values, if it is included in this standard, this should also be made applicable to ATC calculations.<br>(R 6.10) Transmission Service Reservations are available on line on OASIS and need not be included in this standard to be exchanged. Also Transmission Service Reservations may be included in ETC when standard for ETC is developed.<br>(R7) The requirement for updating AFC values should be in NAESB Business Practices. This requirement is also applicable to ATC calculations.<br>(R11) There are more requirements to be included in the AFC methodlogy than the ATC methodology (R5 and R11 are applicable to AFC, and only R11 is applicable to ATC). There does not appear to be a requirement for Transmission Providers using ATC to include items in R1 - R3 in ATC calculation Methodology. It should be made consistent.<br>(R12), (R13), (R14) These requirements can be included in R11 as additional sub requirements. There does not seem to be any justification to keep them as separate requirements and not to be included in the calculation methodology. |
| **Response:**<br>R3: This information is needed for reliability-related needs. The requirement was revised and no longer includes any reference to the frequency for data exchange.<br>R4 The requirements for calculating AFC have been moved into their own standard and include much greater specificity than the equation that was used in the first draft of MOD-001. Please see MOD-030.<br>R5.1 The SDT agrees that this requirement applies to the rated system path methodology as far as requiring the Transmission Service Provider to identify his method of adjusting the ATCs for Firm and Non-Firm Reservations for transparency purposes. Please see the new requirements | | | |

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| **Commenter** | **Yes** | **No** | **Comment** |
| in MOD-028 and MOD-029.<br>R5.3 The revised standard (MOD-001) and proposed new standards for calculating ATC (MOD-028, MOD-029 and MOD-030) do not include any references to OASIS.<br>R6.3 The revised requirement for TSPs to exchange data still include the requirement to exchange the generation dispatch order, but the sub-requirement to update the order before each peak load season has been dropped from the revised requirement.<br>R6.8 and R7. AFC values should be converted to ATC at the same intervals and should be updated at the same intervals as ATC and this is reflected in the revised MOD-001 and new MOD-030<br>R6.10 The requirement to post the latest ATC value on OASIS is being addressed in a NAESB business practice.<br>R12. The revised MOD-001 requires the TSP to develop a document called "Available Transfer Capability Implementation Document" and this document must contain the names of the TSPs with which the TSP exchanges data for use in determining ATC.<br>R13: The drafting team does not agree that R13 should be included in R11 as a sub-requirement.<br>R14: The drafting team removed R14. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice. | | | |
| ERCOT | | | ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology. |
| **Response:** If ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | | | |
| Grant County PUD | | ☑ | "R11.4 Identify the contingencies considered in the ATC and AFC calculation methodology". Is this appropriate? This could be an extensive list in some cases, it could create a security risk, or it could be leveraged for market power.<br><br>"R14 The Transmission Service Provider shall require that the Transmission Customer provide both ultimate source and sink on the Transmission Service Request and shall require that that Transmission Customer use the same source and sink on the Interchange Transaction Tags." Shouldn't the TSP only focus on that part of the transmission that he is providing service for? POD and POR? I am not sure if the intent here is to do specific point of generation to point of usage scheduling. If it is, this is not appropriate for our situation. We meet our schedules with a portfolio of generation and meet our loads with a series of contiguous PORs. We do not to be overly specific and |

| Question #12 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | burdensome. |
| **Response:**<br>R11.4: Including or addressing the contingencies considered is appropriate to ensure consistency and transparency.<br>R14: The drafting team removed R14. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice. | | | |
| IESO | | ☑ | (i) The text box next to R5 says: [Please note that it may appear that the AFC methodology contains more requirements than that ATC methodology. Due to the characteristics of the ATC methodology, the corresponding level of detail will be contained in the standard that determines TTC (e.g. FAC 12 or FAC 13) when it is revised.]<br>We interpret this text box applies to both R5 and R6.<br>We agree that the two methods are different and therefore may need different detailed requirements in certain aspects. However, many of the sub-requirements in R5 and R6 appear to be applicable to the ATC calculation methodology as well hence the detailed requirements can also be addressed in this standard. Moreover, addressing detailed ATC calculation requirements in FAC-012 or –013 appears to be a misfit since the latter standards deal with Transfer Capabilities (and to be revised to deal with Total Transfer Capabilities as suggested in Q14, below), which are solely reliability parameters. Moreover, having the detailed ATC calculation requirements placed in a separate standard would leave room for confusion to the standard users.<br>(ii) R6.5. Please see comments under Q9.<br>(iii) R11.4 The contingencies considered and applied in determining the ATC or AFC would be the same sets used for operating studies and planning studies which could include all possible Category B and Category C contingencies on the TSP's system. It would be near impossible to identify them all. This requirement is implied by R11.2, and where necessary, R11.2 can be expanded to ensure that the ATC and AFC shall be determined with the same set of contingency criteria applicable to the reliability assessment of the like time frame.<br>R11.5 We do not understand this requirement. Does it mean that for ATC and AFC calculation, the model and assumptions must be the same as those used for expansion planning? Note that calculations of ATC and AFC need to consider planned outages to BES facilities, whereas expansion planning may not. Also, if this is the requirement, what are the parallel requirements for ATC and AFC calculation in time frames less than 13 months? |
| **Response:** | | | |

| Question #12 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| Response to all comments: MOD-001 was revised and the intent of MOD-001 is now distributed between 4 standards – with MOD-001 as an 'umbrella' standard, and each of the other three standards (MOD-028, MOD-029, MOD-030) addressing one of the three methods of determining ATC. Each of the three standards that addresses one of the methods of determining ATC also includes related requirements for TTC (or TFC) and ETC. With this rearrangement, each of the 'new' standards includes much more definition than was included with the first draft of MOD-001. Please review the proposed standards. | | | |
| AECI | ☑ | | |
| FRCC | ☑ | | |
| ITC Transco | ☑ | | |
| KCPL | ☑ | | |
| MRO | ☑ | | |
| MidAmerican | | ☑ | As noted in our General Comments above, MidAmerican does not believe the standard as currently drafted complies with FERC Order No. 890. |
| **Response:** The drafting team agrees that the first draft of MOD-001 needed to be revised in order to comply with FERC Order 890. Please see the new set of standards that relate to ATC. | | | |
| MISO | | ☑ | The standard needs to be revisited in light of the Order 890 to make sure consistent measures are applied to all calculations. |
| **Response:** The drafting team agrees that the first draft of MOD-001 needed to be revised in order to comply with FERC Order 890. Please see the new set of standards that relate to ATC. | | | |
| NCMPA | | ☑ | R14 should be eliminated. The proposed source/sink requirement is inconsistent with established trading and scheduling protocols, is not necessary to the reliability of the bulk electric system and conflicts with the principles established to guide the development of reliability standards. Requiring the same ultimate source and ultimate sink on the Transmission Service Request and the Interchange Transaction Tag will harm commercial use of transmission service. It will force transmission users to redirect transmission service on OASIS every time a source or sink changes, even in cases where the source/sink combinations are electrically equivalent. This new practice will provide little, if any, benefit for reliability.<br><br>If the drafting team feels this requirement is still needed, it should be passed to NAESB for inclusion as a business practice. |
| **Response:** R14: The drafting team removed R14. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice. | | | |

| Question #12 | | | |
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| Commenter | Yes | No | Comment |
| NPCC CP9 | | ☑ | R12 – First, this requirement should be placed under R11, because R11 contains the items that must be 'identified' in the TSPs ATC methodology<br>Second, exchanging data with neighboring TSPs is important only if the data held by one TSP is necessary for another TSP to calculate its ATC. Therefore, R12 should be redrafted to read as follows:<br><br>"Identify any other Transmission Service Providers from which data is received for use in calculating its ATC or AFC"<br><br>Data exchanges that are required as part of the TTC calculation should be specified in the TTC Standard. |
| **Response:** R12. The revised MOD-001 requires the TSP to develop a document called "Available Transfer Capability Implementation Document" and this document must contain the names of the TSPs with which the TSP exchanges data for use in determining ATC.<br>Note that there under the drafting team's proposal, there will not be a separate standard to address TTC. | | | |
| NYISO | ☑ | ☑ | R 6 - We suggest that we require that a requester must demonstrate a reliability related need for the data. This will ensure an effort to provide the data is warranted.<br><br>R 6.3 - It is unclear what the phrase 'generation dispatch order' refers to. |
| **Response:** R6: The requirement does include the proposed language.<br>R6.3 – in the revised MOD-001 this is R6.2 and states:<br><br>Generation dispatch, in the form of dispatch order, participation factors, or block dispatch.<br><br>Please let us know if additional clarification is needed. | | | |
| ODEC | | ☑ | I think we need to have a firm definion for the ATC/CBM/TRM terms before a final standard on them should be voted upon as this will impact the language in the standard. |
| **Response:** Agree. The standards on ATC/CBM/TRM/AFC/ETC should be voted upon as a complete package so that all definitions are understood in the context of related standards. | | | |
| Progress Energy Marketing | | ☑ | Progress Energy Marketing disagree with R14, which would require Transmission Customers to provide ultimate source/sink on the Transmission Service Request. By your own definition, a Transmission Service Request is a service request by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.<br><br>The ultimate source/sink requirement is incompatible with the market's trading and scheduling practices. Forward hedging is commonly transacted at Hubs, with the product defined as an "into-HUB". A supplier who delivers energy to an "into-HUB" sale cannot foresee where the buyer will ultimately sink the energy. The supplier may need to purchase transmission to the Hub's interface, but cannot know in advance what sink to input in a transmission Service Request on an upstream system.<br><br>The ultimate source/sink requirement would have an adverse impact on market development as well |

| Question #12 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | as market activity |
| **Response:** R14: The drafting team removed R14. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice. | | | |
| Progress Energy | | ☑ | R3 – What is the intent of this requirement? If the intent is to provide data within 7 days of the request then the requirement needs to be reworded.<br><br>R8 – R14 should apply to "ATC" not "ATC and AFC" because AFC is just an ATC engine, and these requirements should be moved to the beginning of the standard, followed by the engine-specific calculation requirements.<br><br>R11.2 – "internal expansion plan" does not apply within 13 month horizon. Should instead be "internal near-term planning"<br><br>R11.5 – reject inclusion of "use the same power flow model" as this is impossible to apply. Many ATC models use NERC MMWG models as their basis. In planning studies, additional lower voltage detail is included.<br><br>Also, the standard should have only one requirement that defines the when and where of ATC methodology ; If you want the same process to be applied across the whole system and across time horizons then say that plainly in one requirement instead of splitting the where and when between R9 and R11. |
| **Response:** R3: The revised standard does not include this requirement.<br>R8 – R14 –Agree. The translation between AFC and ATC has been addressed in the proposed MOD-030.<br>R11.2 and R11.5 The revised MOD-001 does not include these requirements. Note that the new standards (MOD-028, MOD-029 and MOD-030) try to achieve the same objective. | | | |
| SCE&G and SERC ATCWG | | ☑ | R3 - The requirement is not clear on timeframes. Is it talking about the current ATC values or values into the future? If so, how far into the future. What is intent? If the intent is to create the obligation to provide current data within 7 days of the request, then the requirement needs to be reworded.<br><br>R4 - IN AFC methodology, TRM and CBM are a flowgate attribute not a path attribute, therefore the formula should be modified.<br><br>R5.1 and R5.2 - Needs clarification of the clause "with respect to how each is treated in the Transmission Service Provider's counter flow rules." This clause appears to limite consideration to counterflows only when other issues impact firm versus non-firm reservations and schedules.<br><br>R5.3 - delete "on OASIS" since it is covered in R10.<br><br>R6 - specify whether forward-looking or historical; |

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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | R6.1 and 6.2- "coordinated transmission system element" is not understood. Rephrase to state "coordinated schedules of transmission system elements to be taken out of service" R6.8.3 - This requirement should allow the use of a minimum daily value during a week for posting as weekly ATC.<br><br>6.10 - remove "when revised".<br><br>R7 - state "at the minimum frequency" to be consistent with R6.8.<br><br>R8-R14 all apply to ATC so remove "or AFC" - also move R8-R14 to the beginning of the standard, followed by the engine-specific calculation requirements.<br><br>R11.2 - "internal expansion plan" does not apply within 13 month horizon. Should instead be "internal operational planning".<br><br>R11.5, change "the same power flow models, and the same assumptions regarding load, generation dispatch, special protection systems, post contingency switching, and transmission and generation facility additions and retirements as those used in the expansion planning for the same time frame." to "power flow models containing assumptions consistent with expansion planning for the same time frame." |
| **Response:**<br>R3. The revised standard does not include this requirement.<br>R4 The SDT is unclear on the comment; however, TRM and CBM are attributes of all three methodologies.<br>R5.1, R5.2 The revised MOD-001 requires all TSPs to identify how they account for counter-flows..<br>R5.3 The revised standard does not include this requirement.<br>R6 The requirement to exchange data was updated and most of the sub-bullets were abbreviated to improve clarity – the sub-requirements that identified how often the data needed to be refreshed were removed.<br>R7. This requirement was removed from the revised standard.<br>R8-R14 The SDT revised MOD-001 so it only contains 'generic' ATC requirements applicable to all three methods of calculating ATC. Each of the three methods is treated in greater detail in a stand-alone standard (MOD-028, MOD-029, MOD-030)<br>R11.2 and R11.5 The revised MOD-001 does not include these requirements. Note that the new standards (MOD-028, MOD-029 and MOD-030) try to achieve the same objective. | | | |
| Southern | | ☑ | R1 and R4 for calculations both firm and non-firm. All references to TTC and TFC need to be move off to FAC 12 and 13. R11.2 phrase "internal expansion planning" be removed.<br>R11.2-11.5 is referencing to TTC and TFC/AFC calculations should be moved to FAC 12-13.<br>R7 what updated information should be coordinated and for what purpose? Is this not a posting issue? The posting and reposting of data in the OASIS system needs to be taken out of this standard and requirements be put into NAESB.<br>R14 the ultimate source and sink hold for. |
| **Response:**<br>R1 & R4 As TTC and TFC are both essential variables within the ATC calculation, they cannot be excluded from the formula. How these | | | |

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| **Commenter** | **Yes** | **No** | **Comment** |
| variables are calculated can be correctly addressed in the FACs.<br>R11.2 and R11.5 The revised MOD-001 does not include these requirements. Note that the new standards (MOD-028, MOD-029 and MOD-030) try to achieve the same objective.<br>R14. The SDT does not understand the intent of the comment "the ultimate source and sink hold for" – however the drafting team did remover R14 from the revised standard. | | | |
| Tenaska | | ☑ | We disagree with R14 which requires the Transmission Service Provider to require Transmission Customers to provide ultimate source and sink on Transmission Service Requests and Transmission Customers must use the same source and sink on Interchange Transaction Tags. The main reasons we disagree with this requirement are that it is incompatible with current market trading and scheduling practices and is not always relevant.<br>When a Transmission Customer reserves transmission for use in a trading hub transaction (e.g., "into Entergy", "into Southern"), it is not always possible for the Transmission Customer to know what the actual source or sink will be at the time of making the reservation.<br>When the source or sink is within a pool, it is not possible to identify the actual generating source or ultimate sink. |
| **Response:** R14: The drafting team removed R14 from the revised standard. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice. | | | |
| WECC ATC Team | | ☑ | |

13. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

**Summary Consideration:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC.

| Question #13 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| ERCOT | | | ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology. |
| **Response:** If ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | | | |
| Manitoba Hydro | | | With CBM I believe that the only reliability portion is the recognition of an adeqacy criteria (i.e. the LOLE study) Once that is established CBM could be defined many ways and is likely in the realm of NAESB. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. | | | |
| APPA | | ☑ | MOD-001 should only deal with ATC? and AFC and not the components. The rules for consistent and accurate methods of determining the individual components will be very complicated and numerous. Attempting to place all of these rules for the components in MOD-001 will make MOD-001 very large and impossible to measure and monitor the requirements. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of | | | |

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| **Commenter** | **Yes** | **No** | **Comment** |
| determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. | | | |
| APS | | ☑ | There should be standardization of the components used in the calculation of ATC and AFC. These standards do not have to be in this standard, however if there are new standards for these components and the new standards should take into account this standard. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. | | | |
| WECC ATC Team | | ☑ | As clarity is essential for each ATC variable, the WECC Team suggests that any further prescription or standardization is addressed in a free standing standard specifically addressing each variable of the ATC calculation. For example, a free standing standard should be initiated for ETC. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. | | | |
| BPA | | ☑ | As written, the proposed standard does not achieve standardization, due in part to the uncertainties and lack of clarity in the variables within the ATC/AFC calculation. However, BPA supports development of individual standards for each variable within the ATC/AFC calculation. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. | | | |
| Duke Energy | | ☑ | See response to Q. #1. TRM, CBM, etc, are defined in other standards. |
| **Response:** The drafting team has created separate standards for TRM and CBM. | | | |
| FRCC | | ☑ | Separate standards are being developed that address the components. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. | | | |
| Grant County PUD | | ☑ | Being too presciptive will raise issues of entities seeking exemptions for one reason or another, there |

| Question #13 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | by confusing the compliance. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. The drafting team is attempting to meet the FERC directives that aim to improve consistency and transparency in the processes used to determine ATC. | | | |
| HQT<br>NPCC CP9 | | ☑ | Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. | | | |
| AECI | | ☑ | |
| ITC Transco | | ☑ | |
| KCPL | | ☑ | |
| MRO | | ☑ | |
| Progress Energy | | ☑ | |
| SCE&G and SERC ATCWG | | ☑ | |
| Southern | | ☑ | |
| Entergy | ☑ | | Yes, these details should be included in standard for TTC, TFC, TRM and CBM. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. | | | |
| NYISO<br>CAISO<br>ISO-NE | ☑ | | NERC should develop some general criteria: What should be included in the TTC, TFC, ETC, TRM, CBM? How should they be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation? |

| Question #13 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Any additional standardization of the other components should be contained in those specific standards not in MOD-001. However, it is important that the details of the methodology for determining TTC, TFC, ETC, TRM and CBM must be permissive to allow for continued operation of markets in those TSPs that do not utilize a physical-rights based system for providing transmission service. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. The SDT is trying to propose Standards that provide for consistency throughout each interconnection to the maximum extent possible taking into account variations in market designs while protecting the Bulk Power System reliability. | | | |
| IESO | ☑ | | Some general criteria (the basis) for determining CBM and TRM should be developed so that a consistent approach is used by all TSPs. |
| **Response:** The drafting team has created separate standards for TRM and CBM. | | | |
| MidAmerican | ☑ | | See General Comments above. In addition to changes required to comply with Order No. 890, the process should be standardized and transparent to the point that another provider, using the same methodology and input data, could duplicate the results of any provider. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. | | | |
| SPP | ☑ | | We recommend developing some general criteria, what should be included in the TTC, TFC, ETC, TRM, CBM, and how they should be calculated (high level guidelines) and what the purpose is of including them in the AFC calculation. |
| **Response:** The drafting team has created separate standards for TRM and CBM. TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC. | | | |
| MISO | ☑ | | |
| ODEC | ☑ | | |

14. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? If you don't believe these are the same, please explain what you feel are the differences between TC and TTC.

☐ Yes — TTC and TC are the same
☐ No — TTC and TC are not the same

**Summary Consideration:** TTC and TFC are addressed in the proposed standards (MOD-028, MOD-029, and MOD-030). TTC/TFC, ETC, and ATC/AFC are too intertwined to effectively split, and the drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC.

| Question #14 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PG&E | | | Since the TC is reliability based, if TTC is not the same as TC, then TTC should be no higher than the TC determined by the Planning Coordinator in the planning horizon and the Reliability Coordinator in the operating horizon. |
| **Response:** The ATC Standards Drafting Team has been asked to develop a definition for TTC. If it is determined that TTC and TC are the same values in the planning and operating horizons, then one will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. A clear distinction would recognize that TTC should be no higher than the TC determined by the Planning Coordinator and the Reliability Coordinator in each of their timeframes. | | | |
| ERCOT | | ☑ | As I recall, the FAC drafting team recognized similarities, but used a different name because they were not considered to be the same. The FAC standards relate more to operational system capabilities and different timeframes, not to the in-advance nature of TTC used in the transmission service market. The FAC drafting team included in the FAC standards that the TTC methodologies shall respect the System Operating Limits which relate to the TC described in the FAC standards. |
| **Response:** The TTC definition and the use of TTC in MOD-001-1 relate to all timeframes (operating and planning). The ATC Standards Drafting Team has been asked to develop a definition for TTC. If it is determined that TTC and TC are the same values in each timeframe, then one will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. TTC and TC (if TC is retained) definitions will respect System Operating Limits. | | | |
| Duke Energy | | ☑ | FAC-012 should apply to TC, which indicates the ability to reliability move large amounts of power between regions, sub-regions and control areas. Test of TC identifies potential transfer limits that may result from loop flows, market activity or contingencies. TTC calculation is required to support market operation without impacting reliability in a negative manner. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the definitions. It is expected that the definition of TTC will identify potential transfer limits in each timeframe (e.g., planning horizon, operating horizon). Potential transfer limits in each timeframe may result from factors such as loop flows, market activity or contingencies, as well as support of market operation. It is expected that factors with the potential to cause a transfer limit can be included in the appropriate timeframe | | | |

| Question #14 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| of each TTC value. If it is determined that TTC and TC are the same values in each timeframe, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. | | | |
| MidAmerican | | ☑ | Given the new requirements in Order No. 890, the definitions TTC and TC must be consistent since Order No. 890 requires consistent methodologies for use in i) planning, and ii) ATC or AFC calculations.<br><br>It should be noted that TC is used for planning and security coordination purposes, while TTC is commercial in nature and must be updated with each ATC calculation to reflect operational conditions. As a result, there may be points in time when TC is not equal to TTC due to the frequency of updates. |
| **Response:** The TTC definition and the use of TTC in MOD-001-1 relate to all timeframes (operating and planning). The ATC Standards Drafting Team has been asked to develop a definition for TTC. If it is determined that TTC and TC are the same values in each timeframe, then one will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. TTC and TC (if TC is retained) definitions will respect System Operating Limits. | | | |
| MRO | | ☑ | |
| IRC<br>ISO-NE<br>CAISO | ☑ | ☑ | This question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to an operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4 of the Comment Form. We believe TTC should be added into the FAC requirements as a defined term. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the definitions. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. For reference, the team asked the chairman of the FAC Standards Drafting Team this question, and his response was, "Transfer Capability as required in FAC 012 and Total Transfer Capability as required by MOD 001 are indeed the same quantities." | | | |
| NYISO | ☑ | ☑ | This question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to an operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4 of the Comment Form. We believe TTC should be added into the FAC requirements as a defined term.<br><br>The Reliability Standards should consider a single term for all standards. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the definitions. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. For reference, the team asked the chairman of the FAC Standards Drafting Team this question, and his response was, "Transfer Capability as required in FAC 012 and Total Transfer Capability as required by MOD 001 are indeed the same quantities." | | | |

| Question #14 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| SPP | | | That question should probably be asked of the drafting team of FAC-012-1 / FAC-013-1 if they had same definition in mind. When reading FAC-012-1 it is optional to apply a described methodology to a operating and/or planning horizon. The TTC as described in MOD-001-1 should be applied to all Horizons listed under question 4. of the Comment Form. It looks like FAC-012-1 is more related to Reliability function (real time /semi real time) and MOD-001-1 is more related to Tariff function. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the definitions. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. For reference, the team asked the chairman of the FAC Standards Drafting Team this question, and his response was, "Transfer Capability as required in FAC 012 and Total Transfer Capability as required by MOD 001 are indeed the same quantities." | | | |
| HQT | ☑ | | This question should probably be asked to the drafting team of FAC-012-1 / FAC-013-1 if they have the same definition in mind. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the definitions. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. For reference, the team asked the chairman of the FAC Standards Drafting Team this question, and his response was, "Transfer Capability as required in FAC 012 and Total Transfer Capability as required by MOD 001 are indeed the same quantities." | | | |
| APPA | ☑ | | TTC and TC are the same value determined by the planners or operation personnel for planning and operating horizons, respectively. It is recommended eliminating one of the terms to avoid confusion. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the definitions. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. | | | |
| BPA | ☑ | | Uncertain. FAC-012 speaks to reliability margins that may be applied when calculating transfer capabilities. This may give rise to inconsistencies between TC which incorporates margins, and ATC standards which, as currently drafted, imply that TRM is calculated separately from TTC. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the definitions. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. | | | |
| Entergy | ☑ | | TTC and TC are same. However FAC-012 is written for reliabiliy assessment of Bulk System. Since Transfer Capability calculations use same algorithm but different base case models, FAC-012 should be modified to include calculation of TTC that can be used for ATC calculations as described in MOD-001. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the definitions. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. | | | |
| FRCC | ☑ | | The TTC definition should be retained. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the the | | | |

| Question #14 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| definitions. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. | | | |
| SCE&G and SERC ATCWG | ☑ | | However, there are different definitions for TTC and TC. The definitions should be the same thus the current definition needs to be clarified. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the definitions. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. | | | |
| WECC ATC Team | ☑ | | Additionally, the NERC Drafting Team should decide which of the NERC Glossary terms best describes this specific capacity and eliminate the other. |
| **Response:** The ATC Standards Drafting Team has been asked to create a clear distinction between TTC and TC or to eliminate one of the definitions. If it is determined that TTC and TC are the same values in the planning and operating horizons, then TC will be eliminated. If it is determined that a definition of TC is needed, then a clear distinction between TTC and TC will be made. | | | |
| Grant County PUD | ☑ | | |
| IESO | ☑ | | |
| APS | ☑ | | |
| AECI | ☑ | | |
| ITC Transco | ☑ | | |
| KCPL | ☑ | | |
| Manitoba Hydro | ☑ | | |
| MEAG Power | ☑ | | |
| MISO | ☑ | | |
| ODEC | ☑ | | |
| Southern | ☑ | | |

15. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards. Please explain your answer:

**Summary Consideration:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. The drafting team developed four proposed standards to address ATC – an 'umbrella' standard that provides a set of requirements that apply to all three methods of determining ATC, and then a separate standard for each of the three methods of determining ATC. Each of the standards that addresses a method for determining ATC, also contains the associated requirements for TTC and ETC.

| Question #15 | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| ERCOT | | | ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology. |
| **Response:** If ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | | | |
| Southern | | | The TFC methodology should be developed in the FAC12-13 standard and not in MOD-001. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| SPP | | | It looks like FAC-012-1 is more related to Reliability function and MOD-001-1 is more related to Tariff function. FAC-012 should probably describe how the Normal Rating and Emergency Rating should be calculated, using what weather conditions and what safety margin for equipment. MOD-001-1 could refer to those definitions and indicate (as an example) that Normal Rating could be used for single element PTDF flow gates and Emergency Rating for OTDF flow gates. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| MRO | | | Both MOD-001-1 and FAC-012-1 should reference the flowgate capability. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| AECI | | ☑ | TFC is well defined in the definitiond of terms in the standard section. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary | | | |

| Question #15 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| consideration. | | | |
| APPA | | ☑ | A Flowgate is another tool to plan and operate to the BES. The Flowgate development and assumptions will be developed by the planners or operation personnel depending on the time horizon. The flowgate rating is determined as part of the FAC package for system rating, SOL determinations, and TTC (TC) determinations. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| BPA | | ☑ | TFC is similar to TC and should be addressed similarly to TC by revising the existing Facility Rating FAC-012-1. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| Entergy | | ☑ | TFC and TTC methodology should be included in the same standard. Since FAC-012 includes TTC, the same standard should include requirements for TFC calculations. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| HQT | | ☑ | If TFC is similar to TTC, it should be dealt in another Standard e.g. the same one that would deal with TTC. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| IESO | | ☑ | TTC and TFC are reliability parameters that are determined by the facility rating methodologies stipulated in FAC-012 and FAC-013, and these values are not determined by the TSP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| IRC<br>ISO-NE<br>CAISO | | ☑ | TTC and TFC are reliability parameters that are determined by the transfer capability methodologies stipulated in FAC-012. These values are not determined by the TSP but by the RC or TOP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| NYISO | | ☑ | TTC and TFC are reliability parameters that are determined by the transfer capability methodologies stipulated in FAC-012. These values are not determined by the TSP but by the RC or TOP. In ATC and AFC calculations, these values serve as the upper bound for assessing and managing available transmission services only.<br><br>The drafting team needs to work with FAC-012/013 to coordinate the determination of TTC and TFC. We believe these values are closely related and are the same on a closed interface. |

| Question #15 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| Manitoba Hydro | | ☑ | I think that the team was well advised to defer this to the facility rating standard team. However a flowgate can be defined by single or multi elements. the team should ensure that the team developing FAC-012 and/or FAC-013 is cover both as well. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| MISO | | ☑ | As explained earlier, the standard needs to be methodology neutral. |
| **Response:** | | | |
| PG&E | | | There is no reliability need to develop a TFC separate from that already developed in the FAC Standards by the Planning Coordinator in the planning horizon and the Reliability Coordinator in the operating horizon. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| Progress Energy | ☑ | | All of the calculations related to ATC should be addressed in the same standard. PE suggests that all requirements be included in MOD-001. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| Duke Energy | ☑ | | TFC and AFC need to be in the same standard because they are interlinked with market issues. FAC-012 and FAC-013 focus on calculation of TC for reliability studies. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| FRCC | ☑ | | All transfer related matters need to be contained in one standard not spead out over multiple documents. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards Please see the summary consideration. | | | |
| SCE&G and SERC ATCWG | ☑ | | All of the calculations related to ATC (TFC, TTC, AFC) should be addressed in the same standard. Suggest that all requirements be included in MOD-001 and that FAC-012 and FAC-103 should be retired. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |
| KCPL | ☑ | | The purpose of the MOD Reliability Standards is to provide the "how to" for modeling and determining operating parameters. The purpose of the FAC Reliability Standards is to provide "you will use" the results of the MOD to operate the bulk electric system. TFC methodology should be defined in the MOD and then how it is used in the FAC. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. Please see the summary consideration. | | | |

| Question #15 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| MidAmerican | ☑ | | MOD-001 should address the methodology and documentation. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. The drafting team currently believes that | | | |
| WECC ATC Team | ☑ | | TFC methodology should be addressed in the same standard as is TTC methodology. This is the logical parallelism to addressing AFC and ATC in the same standard. |
| **Response:** TTC/TFC, ETC, and ATC/AFC are intertwined, and cannot easily be split into multiple standards. The drafting team currently believes that | | | |

16. When calculating ATC and monthly, daily, weekly, and hourly AFC values, what time horizon(s) for CBM should be used and which reliability function(s) should make the CBM calculations? Please explain

**Summary Response:**
The drafting team wanted input from all entities BEFORE writing the CBM standard and this was the most convenient place to ask this question. Based on stakeholder comments and FERC Orders 890 and 693, the drafting team has drafted a CBM standard (MOD-004) that includes the following:

- The TSP is assigned the responsibility for determining CBM
- The standard for CBM does not contain a requirement to update CBM on a fixed schedule as CBM is only set aside upon the request of an LSE- the proposed standard does include a requirement that the LSE make a request for CBM at least annually which will result in CBM being updated at least annually
- Each of the three standards that includes one of the methods of calculating ATC identifies how to use CBM in the determination of ATC and requires the use of CBM in calculating ATC over all time horizons.

This shall serve as the summary response to all opinions offered in response to this question.

| Question #16 | |
|---|---|
| **Commenter** | **Comment** |
| AECI | Operating Horizon - hourly and daily<br>Planning Horizon - weekly and monthly |
| APPA | In determining ATC for the different time horizons the CBM must match the same time horizon. The definition of ***Capacity Benefit Margin (CBM) is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements****.* The primary responsibility of the CBM for the Hourly ATC will be the LSE to meet its responsibility of providing all energy and capacity for load, including operating reserves for the upcoming hours. The Monthly and Daily ATC values are long and short term planning issues where the planners project how much transmission capacity will be needed to ensure access to generation from interconnected systems to meet generation reliability requirements. |
| APS | The Load Serving Entity should make the CBM calculations for all the time horizons (monthly, daily, weekly and hourly) listed above. |
| BPA | BPA does not employ CBM and declines to comment. |
| CAISO | The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM. |
| Duke Energy | Resource Planner should make the calculation. |
| Entergy | There can be different CBM for different time horizons. CBM should be calculated based on the uncertainties of generation available within the Transmission Service Provider area to meet loads. Load Serving Entities should calculate CBM for their loads based on their loads and generation available to serve these loads. In case of Reserve Sharing Groups, loads and generation for the entire group should be included to calculate CBM. Or if CBM calculations are performed on a Balancing Authority Area basis, the entire load and genereation in that area should |

| Question #16 | |
|---|---|
| **Commenter** | **Comment** |
| | be used for these calculations, even if there are more than one LSEs within that area. |
| ERCOT | ERCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology. |
| **Response:** If ERCOT has comments that would assist the drafting team in improving the proposed definition, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | |
| Grant County PUD | The Transmission Operator should be continuously be updating all of these values. |
| HQT | The question is inappropriate, because the standard does not attempt to define the methodology for CBM. |
| IESO | All time horizons should be used in accordance with the corresponding ATC calculation time frame. The value of CBM should be determined by the TSP based on the need demonstrated by the LSE. |
| IRC | The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM. |
| ISO-NE | The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM. |
| KCPL | MOD-004-0 R1.2 already requires that the frequency for CBM updates be identified by the Regional Reliability Organization and its members and it should be left that way. CBM should be used in all time horizons. |
| **Response:** If left as is, this would be a 'fill-in-the-blank' requirement and is not enforceable. | |
| Manitoba Hydro | I believe this and other features of CBM should be determined by NAESB. |
| MEAG Power | Since CBM is a reliability margin, the long term or annual value should be used for the monthly, daily and weekly ATC calculations. It should be calculated by LSE. |
| MidAmerican | The TSP should calculate the CBM and the timing and methodology should be well documented. |
| MISO | These parameters are individual transmission providers business practices. |
| MRO | At least calculate hourly CBM values for applicable entity TSP. |
| NCMPA | In determining ATC for the different time horizons the CBM must match the same time horizon. The primary responsibility of the CBM for the Hourly ATC will be the LSE to meet its responsibility of providing all energy and capacity for load, including operating reserves for the upcoming hours. |
| NPCC CP9 | The question is inappropriate, because the standard does not attempt to define the methodology for CBM. |
| NYISO | The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for CBM. |
| ODEC | Must be the same time horizon for consistency. |

| Question #16 | |
|---|---|
| **Commenter** | **Comment** |
| Southern | Addressed in CBM standard. In general, CBM is applicable to each time horizon in the context of calculating firm import ATC. |
| SPP | We don’t use CBM, so we don’t really have an opinion. |
| WECC ATC Team | This question is best deferred to the CBM standard.<br><br>That said, the LSE should be the entity that determines CBM and should also be allowed the authority to call on the CBM when appropriate.<br><br>In keeping with Order 890, P. 358 and also MOD-05 as currently implemented, the WECC Team suggests that CBM be recalculated no less than annually with allowance to recalculate more frequently as circumstances change.<br><br>To the extent CBM is not scheduled (remains “unused”) CBM must be posted on OASIS on a non-firm basis. Order 890, P. 354. |

17. When calculating ATC and monthly, daily, and hourly AFC values, what time horizon(s) for TRM should be used, and which reliability function(s) should make the TRM calculations? Please explain.

**Summary Consideration:** The drafting team wanted input from all entities BEFORE writing the TRM standard and this was the most convenient place to ask this question. Based on the comments received, and consideration of the FERC Order 890 and 693, the drafting team is adding the following specificity to the standard for TRM (MOD-008)

- The Transmission Planner and Transmission Operator will be assigned responsibility for calculating TRM and providing the TRM value to their TSPs
- TRM will be calculated for each of the following time horizons to align with the time horizons for calculating ATC:

  **The TOP will be calculate TRM as follows:**
  Same day and real-time.

  Day-ahead and pre-schedule.

  **The Transmission Planner will calculate TRM as follows:**
  - Time period beyond the day-ahead and pre-schedule

  This shall serve as the summary response to all opinions offered.

| Question #17 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| AECI | | | Operating Horizon - hourly and daily<br>Planning Horizon - weekly and monthly |
| APPA | | | In determining ATC for the different time horizons the TRM must match the same time horizon. The planners that plan at the different time horizons would be the best. The SDT has come up with a proposal of using a percentage of one of the system values that has been determined by the planners. This would be a very good ~~comprise~~ compromise and promotes a level of consistent calculations. |
| APS | | | The Transmission Service Provider should make the TRM calculations for all the time horizons (monthly, daily, weekly and hourly) listed above. |
| BPA | | | The issue of time horizons should be determined through development of the TRM standard. The Transmission Service Provider should be reponsible for determining TRM. |
| CAISO<br>HQT<br>IRC<br>ISO-NE<br>NPCC CP9 | | | The question is inappropriate, because the standard does not attempt to define the methodology for TRM. |
| NYISO | | | The question is inappropriate for MOD-001, because the standard does not attempt to define the methodology for TRM. |
| Duke Energy | | | TRM should be looked at as a seasonal requirement, and Duke Energy would use the same TRM |

| Question #17 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | value for monthly, daily and hourly calculations. Transmission Planner makes the TRM calculation. |
| Entergy | | | There can be different TRM for different time horizons. Farther in future, less certain are the conditions, therefore, higher TRM. Since TRM is based on combination of uncertainties of different elements, each components will have different contributions to TRM for different time horizons. |
| ERCOT | | | RCOT does not use this methodology and has no comment. The standard should provide for ERCOT's non-transaction-based methodology. In addition, ERCOT presently has set TRM and CBM to zero in its operating and market activities. |
| **Response:** If ERCOT has comments that would assist the drafting team in improving the proposed standards, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | | | |
| FRCC | | | The TRM should relate to the time horizon of the product. TRM is indtend to account for uncertainties in the bulk electric system and should be determined by the Transmission Service provider. The degree of uncertainty increases in relationship to the product timeframe. The system conditions for hourly are known with a much greater degree of accuracy than for the 13th month. Additionally, the period of exposure to a risk is much greater on a month product than on an hourly product. The probability of a unit or line tripping during the period of a confirmed transaction is much greater for a monthly product than for a daily product. |
| Grant County PUD | | | The Transmission Operator should be continuously be updating all of these values. |
| IESO | | | All time horizons should be used in accordance with the corresponding ATC calculation time frame. The value of TRM should be determined by the TOP and RC depending on the reason for the need of interconnection assistance to cover uncertainties that could affect transmission reliability. |
| KCPL | | | MOD-008-0 R1.1 already requires that the frequency for TRM updates be identified by the (a) Regional Reliability Organinzation and its members and it should be left that way. TRM should be used in all time horizons. |
| Manitoba Hydro | | | This would depend on the need for TRM. IF TRM is required to coordinate interregional stability concerns, it may needed in all horizons. If TRM is used to compensate for uncertainty in Load Forecasts, it should not be used in the operating or day ahead horizon. |
| MEAG Power | | | Since TRM is a reliability margin, the long term or annual value should be used for the monthly, daily and weekly ATC calculations. It should be calculated by TP. |
| MidAmerican | | | The TSP should calculate the TRM and the timing and methodology should be well documented. |
| MISO | | | These parameters are individual transmission providers business practices. |

| Question #17 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| MRO | | | At least calculate hourly TRM for applicable entity TSP. |
| NCMPA | | | In determining ATC for the different time horizons the TRM must match the same time horizon. The planners that plan at the different time horizons would be the best. |
| ODEC | | | Must be the same time horizon for consistency. |
| Southern | | | Addressed in TRM standard. In general, TRM is applicable to each time horizon in the context of calculating firm import ATC. Discussion is needed to determine whether TRM should be included in determing non-firm ATC and in export ATC calculations. |
| SPP | | | TP should calculate the TRM value. TRM should be a seasonal (or yearly value), based on the largest available resources (not scheduled to have maintenance) in that season. If it is a yearly value it should be based on the largest unit. We don't think TRM should be a Monthly value, because maintenance of Resources can change and you might sell service on a lower TRM based on scheduled maintenance of the largest unit. If the scheduled maintenance changes and largest unit moves back in that Month you could potential have oversold system. To play it safe TRM should be seasonal or yearly value. A TP could decide based on a current outage of the unit which was the basis for current TRM value, to lower TRM for the time frame of the outage however we don't think that this type of detail should be incorporated or described in the MOD-001-1. |
| WECC ATC Team | | | This question is best deferred to the TRM standard.<br><br>That said, the Transmission Service Provider in conjunction with its Transmission Planner should determine the TRM.<br><br>How often TRM should be calculated is dependent upon what elements go into the TRM as will be dictated in the TRM standard. If load forecast error becomes part of TRM, the TRM should be adjusted hourly. By contrast, if the TRM is solely to address seasonal changes that an annual then on/off peak recalculation may be in order. |

18. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

**Summary Consideration:**
Most commenters had no concerns, other than to say that the drafting team should be consistent with Order 890 and 693.

| Question #18 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| Duke Energy | | | We understand that the drafting team is examining the impacts of FERC Order 890 for conflicts with the proposed standard. |
| **Response:** The drafting team has addressed FERC Order 890 and FERC Order 693 with respect to the set of ATC/TTC CBM/TRM standards. | | | |
| Entergy | | | No, however requirements in the proposed standards should be consistent with those included in FERC OATT, Orders 888, 889, and recently issued FERC Order 890. |
| **Response:** The drafting team has addressed FERC Order 890 and FERC Order 693 with respect to the set of ATC/TTC CBM/TRM standards. | | | |
| IESO | | | No conflicts. But there are markets that do not provide physical transmission services which require the calculation and posting of ATCs and AFCs. In addition, there are entities that are not under FERC's jurisdiction and hence may not provide any transmission services. |
| **Response:** The drafting team acknowledges your comments. | | | |
| IRC<br>ISO-NE<br>NYISO | | | We are not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement, because the proposed language is broad enough to accommodate the manner in which ISOs/RTOs provide transmission service in a market-based environment. As NERC continues to develop Standards to govern reliability practices surrounding the calculation of ATC/TTC/AFC/etc... (and coordinate with NAESB regarding its development of associated business/commercial practices) in response to the Commission directive in Order No. 890, NERC's Standards must be broad enough so as not to frustrate the market-based manner in which ISOs/RTOs provide transmission service.<br><br>As the Commission ruled in Order No. 890 with regard to, among other things, the standardization of ATC calculations, "some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the pro forma OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs."<br><br>See Order No. 890 at P158. The proposed MOD-001 Standard appears to be in line with this direction. |
| **Response:** The drafting team acknowledges your comments. | | | |
| MidAmerican | | | See General Comments above. FERC Order No. 890 makes the current standard obsolete and it |

| Question #18 | | | |
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| Commenter | Yes | No | Comment |
| | | | must be significantly revised. |
| **Response:** The drafting team acknowledges your comments. | | | |
| MISO | | | The FERC order 890 calls for more transparency in the AFC/ATC calculations. This standard did not seem to focus on that aspect, in fact, it gives two different standards for transparency: ATC methods have no transparency, and AFC methods are completely open. In light of the goals expressed in FERC's final rule on this issue, for both transparency and consistency of calculation, the committee should withdraw this proposal and review it carefully in light of FERC's Order 890 While the committee has worked hard to bring the standard to this point, Midwest ISO believes this issue is too important to simply forge ahead without discussing the standard's present definitions and requirements in light of the FERC final rule on this subject, issued the same day this standard was released for comment. |
| **Response:** The drafting team acknowledges your comments. | | | |
| NPCC CP9 | | | No, As the Commission noted in Order No. 890, "some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the pro forma OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs." See Order No. 890 at P158. We find that the language as proposed is broad enough to accommodate the manner in which ISOs/RTOs provide transmission service in a market-based environment and satisfies the Commissions note in Order No 890 on this subject.<br><br>In short, so long as a TSP is following approved Market and Tariff rules that are part of a Commission-sanctioned market design, such rules should be deemed consistent with this Standard. |
| **Response:** The drafting team acknowledges your comments. | | | |
| SCE&G and SERC ATCWG | | | Some TSP's OATT have requirements that components of ATC be provided by third parties. For example, in one case, a TSP is required to use the AFC calculations provided by the Reliability Coordinator in determining its ATC. |
| **Response:** The drafting team acknowledges your comments. | | | |
| Southern | | | The drafting team should consider whether particular directives in Order 890 adversely impact reliability and respond appropriately. |
| **Response:** The drafting team acknowledges your comments. | | | |
| SPP | | | No, we are not aware of any. Some TP's may find the need to include more detail into MOD-001-1 to address the concerns raised in the FERC Order No. 890. |
| **Response:** The drafting team acknowledges your comments. | | | |

19. Do you have other comments that you haven't already provided above on the proposed standard?

| Question #19 | |
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| **Commenter** | **Comment** |
| AECI | The standard does not provide a clear distiction for use of ATC verses AFC. It is our understanding that Requirements R1-R3 do not apply if the AFC methodology is used. For R4 to R6 if the AFC methodology is used then the TSP is not required to post ATC values, however AFC values would be posted. |
| **Response:** As originally envisioned, requirements R1-R3 would have applied to all of the methods because ATC is required to be calculated by whichever method is chosen. Note that MOD-001 was significantly revised and no longer contains these requirements. | |
| APPA | MOD-001 needs to address how the AFC calculations should be converted to the ATC calculations.<br>MOD-001 needs to show that the ATC formulas for Monthly, Daily, and Hourly calculations are for different paths or networks. MOD-001 needs to show the formula to determine $ATC_{nonfirm}$ for Monthly, Weekly, and Daily calculations.<br>The "future development plan must be modified to include the introduction and assistance of the NERC Compliance Staff to assist the team in developing Measurements, VRFs, and suggested terms of the compliance sections of the Standard. |
| **Response:** Please see the proposed MOD-030. This new standard addresses ATC developed using the flowgate network response method and includes requirements for converting AFC to ATC.<br>The proposed standards (MOD-028, MOD-029, and MOD-030) do not include the formulas that were included in the first draft of MOD-001. The proposed standards all include much more detail in what is required to calculate ATC. Each of the three new standards has clear requirements to distinguish between 'firm' and 'non-firm' ATC.<br>The drafting team wants to move towards consensus on the requirements in the proposed standards before adding all of the compliance elements, | |
| BPA | R4. The formula in R4 describing AFC calculations is not accurate in the way it describes the application of distribution factors. Distribution factors are not necessarily applied to all of the components of the AFC calculation. Distribution factors are applied to transactions to allocate the percentage of the transaction that will flow on each applicable flowgate.<br><br>R14. The requirement to provide the ultimate source and sink on the Transmission Service request, especially when the source or sink is on the other side of an interchange point, is not necessarily required for a Transmission Service Provider to determine the ATC/AFC impacts of a request. Additionally, this requirement may create difficulties for Transmission Customers since the ultimate source and sink may not be known at the time of the request submittal. |
| **Response:** R4. The treatment of the flowgate network response method of calculating ATC is now addressed in MOD-030 and does includes much more specificity on the use of distribution factors.<br>R14: The drafting team removed R14. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice. | |
| CAISO | To provide clarity and uniform application in the calculation of AFC and ATC the CAISO offers the following: When |

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| **Commenter** | **Comment** |
| | calculating AFC in the forward markets, this calculation should include counter transmission service requests. In WECC, there is currently no virtual schedules and transmission reservations are expected to provide energy flows real-time (or adjustments are made in real-time to ensure ties are not overscheduled). The formula for AFC would look like: AFC=TFC-(TRM*distribution factor) –(CBM*distribution factor)- the sum of(ETC impacts * respective Distribution Factors) + (counter transmission reservations *respective distribution factions). A similar formula could be provided for calculation of ATC. |
| **Response:** Counter-flow requests cannot always be considered in the AFC (or ATC) calculation because the transmission created by a requested counter-flow transaction is not “available” until the requested transaction is confirmed, in which case the transaction becomes part of ETC. Please review the proposed MOD-030. | |
| Duke Energy | We have not factored impacts of FERC Order 890 into these comments.<br>Editorial comment on R.12 - should read "Each Transmission Service Provider shall identify other Transmission Service Providers with which the data used in the calculation of ATC or AFC is exchanged." |
| **Response:** The first draft of MOD-001 has been significantly revised to address FERC Order 890 and Order 693. The first draft of MOD-001 was posted before FERC Order 890 was released.<br>R12: The revised MOD-001 requires the TSP to develop a document called “Available Transfer Capability Implementation Document” and this document must contain the names of the TSPs with which the TSP exchanges data for use in determining ATC. | |
| Entergy | The Standard Drafting Team has a difficult task of including FERC expectation of making ATC calculations consistent and transparent. Due to different operating practices in different regions of the country, it will be difficult to come up with consistent (one size fits all) method. Regional differences should be recognized keeping in view how these are affecting reliability. Any issues that are commercial in nature should be left to NAESB to include in their Business Practices Standards. |
| **Response:** The drafting team agrees with all of these comments. | |
| ERCOT | Yes. No Regional Differences are identified in this draft. However, ERCOT does not use this methodology and therefore this shall not apply to operating activities and market activities in ERCOT. The standard should provide for ERCOT's non-transaction-based methodology. |
| **Response:** If ERCOT has comments that would assist the drafting team in improving the proposed definition, those comments would be welcome. Within Order 693, the FERC states in paragraph 1007 the following:<br><br>Responding to CenterPoint’s proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained (in the NOPR) that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.<br><br>As such, we suggest that ERCOT consider this as a possible avenue for further exploration. | |
| Grant County PUD | Thank you for the opportunity to comment. Other comments will arise after further refinement of this standard, and our further study of it. |
| **Response:** The drafting team also thanks you for your comments. | |

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| **Commenter** | **Comment** |
| HQT | The drafting team must engage in additional drafting to address the concerns raised by Order No 890. |
| **Response:** The drafting team agrees that the current standard must be significantly revised. The draft standard was posted before FERC Order 890 was released. | |
| IESO | Requirement 12 should be R11.6. |
| **Response:** R12: The drafting team will reword the requirement and consider moving it to a sub-requirement of R11. | |
| KCPL | No. |
| Manitoba Hydro | It is of paramount that a standard is developed that standardizes assumptions and processes. There are many reasonable processes available to develop and study impacts on flowgates. If all transmission providers would be able to contain all the impacts from their operation on their systems, there would not bee the need for this standard. Each transmission provider could use what ever set of assumptions that the wished as long a reliability on their system was maintain. But the very fact that this is not possible to contain impacts requires standardization of assumptions and processes. This is required to insure that when a transmission provider is assessing the impact on a flowgate in a neighbouring system that the assumptions used to assess the impacts are the same assumptions used to develop and study the flowgate. This can only be done if every transmission provider is using one set of assumptions and on set of processes.<br>It appears by what has been presented here that the team is trying to accommodate various processes that are used by the industry today. In my opinion, this can only be done by compromising the reliability.<br><br>It also appears (and I may be wrong) that the team has not fully come to terms with what is a reliability concern and what is a commercial concern. For example, in my opinion, CBM is mostly a commercial concern. CBM has historically been used to account for shortfalls in adequacy studies. I am the first to admit that this is purely a reliability concern. However once the adequacy study has determined the shortfall, there are many methods of mitigating that shortfall ranging from simply putting a CBM value on the ties with your neighbour who is most likely to have excess capacity when you need it to belong to a capacity reserve sharing pool that will reserve transmission through the use of CBM. The only reliability concern in all of this is the identification of the adequacy concern and need to have a posting value to mitigate the adequacy concern. The commercial concerns of how to mitigate those concerns should be left to NAESB. |
| **Response:**<br>The SDT concurs with Manitoba as well as FERC that the fine line between reliability and commercial interests is not easily discernable. The SDT further concurs that business practices should be left to NAESB as is the parallel NAESB process currently underway | |
| MidAmerican | See General Comments above. FERC Order No. 890 makes the current standard obsolete and it must be significantly revised.<br><br>In addition, each of the three methodologies should address contract path limitations. Not only should each methodology address physical limitations of the system, but contractual limitations as well. |
| **Response:** The first draft of MOD-001 has been significantly revised to address FERC Order 890 and Order 693. The first draft of MOD-001 was posted before FERC Order 890 was released.<br>The drafting team also agrees that contract path limitations must be addressed by all three methodologies, probably more appropriately in the | |

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| **Commenter** | **Comment** |
| calculation of TTC. | |
| MISO | The standard includes formulas. The formulas should be left to the business practices of the provider and the terms. |
| **Response:** A standard that is intended to make the calculation of values consistent for the purpose of maintaining a reliable system should include the formulas needed to make the calculations. | |
| MRO | a. With FAC 010, 011,012, and 013 why is MOD-001-1 needed for reliability? MOD 001-1 seems to be an OATT business practice issue.<br>b. Informational references to the corresponding development of NAESB business are irrelevant in the Canadian context as Canadian jurisdictions are not obligated to follow NAESB business practices. |
| **Response:** MOD-001 is not a business practice issue. NERC and NAESB are working together to draft companion standards where NERC requirements address reliability concerns and NAESB addresses business practices. | |
| NPCC CP9 | The drafting team must engage in additional drafting to address the concerns raised by Order No 890. |
| **Response:** Agree. The first draft of MOD-001 has been significantly revised to address FERC Order 890 and Order 693. The first draft of MOD-001 was posted before FERC Order 890 was released. | |
| Progress Energy | PE suggests renaming the Standard "ATC Calculation Methodologies" and restate Purpose. AFC is just one engine type used to calculate ATC. |
| **Response:** The drafting team will consider re-titling the standard, in light of the FERC Order 890 requirement to convert AFC to ATC. The standard drafting team does not understand the comment "AFC is just one engine type used to calculate ATC." | |
| SCE&G and SERC ATCWG | Suggest renaming standard to ATC Calculation Methodologies and restate Purpose. AFC is just one of the engines used to calculate ATC. |
| **Response:** The drafting team will consider re-titling the standard, in light of the FERC Order 890 requirement to convert AFC to ATC. The standard drafting team does not understand the comment "AFC is just one engine type used to calculate ATC." | |
| Southern | R5.1 and R5.2 only cover the aspects of non-firm with dealing with an entity's counter flow rules. This could be resolved by adding equations that outline the firm and non-firm aspects of AFC. Firm and non-firm also differ in the treatment of TRM/CBM and postbacks of unscheduled service.<br><br>R8 If Firm and Non-firm equations are used for ATC/AFC this requirement would not be necessary.<br><br>R11.2: There is no "internal expansion planning" during these time frames. The phrase should be deleted. It is unclear what is meant by "use the same criteria and assumptions used to conduct reliability assessments and internal expansion planning for different time frames"<br><br>Generally, expansion planning considers an N-2 approach as opposed to an N-1 in the operating horizon. Expansion planning also generally considers more robust dispatch assumptions in the local area under review. Also, although transfer analysis is a consideration in expansion planning, generally expansion plans are driven by local load serving constraints (thermal or voltage), not ATC considerations (limits to transfers). It would be inappropriate to utilize the same assumptions for ATC as expansion planning.<br><br>R11.3: R11.2 states that the same criteria should be used and R11.3 states that the rationale for any differences should be documented. Does this allow of differences in R11.2? |

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| **Commenter** | **Comment** |
| | R11.4: This is not a big deal, but contingencies would be considered in the TTC and not the ATC. It is unclear what is meant by "Identify the contingencies considered in ATC". Is this a general statement of N-1 or specific contingencies used in the TTC assessment?<br>R11.5: This is a planning issue, but this requirement could be problematic and difficult to comply with, especially using the same power flow models. The intent was to make sure that the requirements that you use to grant service were no more stringent that those used to plan for system expansion. We might want to consider suggesting a rewording. Generic ATC values calculated beyond 13 months are not used for addressing TSRs. I am not aware of yearly transmission service being evaluated absent a TSR study of the specific transfers, which would be performed under the planning process, so the models would be one in the same. I assume the "for the same timeframe" language indicates that the assumptions for beyond 13 months do not need to match the assumptions within the 13 monthly timeframe. In addition to the differences in expansion planning discussed above, planning models generally include firm commitments for long term service which may be inappropriate to use in operations (such as CT plant modeled on in April).<br><br>R14 Under the OATT, transmission customers are not required to buy full path transmission service. This would also seem to significantly complicate the redirecting of service, another customer right offered under the OATT. |
| **Response:**<br>R5.1 & R5.2 The revised standard requires the TSP to identify how it accounts for counter-flows – and each of the three standards that includes requirements for developing ATC includes additional requirements related to counter-flows.<br>R8. With the revised standards, each of the three standards that addresses one of the methodologies for determining ATC includes its own requirements for calculating 'firm' and 'non-firm' ATC.<br>R11.2-11.5 - R11.2-11.5 do not apply to users of the Rated System Path Methodology for the calculation of ATC. They do apply to the Rated System Path Methodology for the calculation of TTC and have been translated the intent of these requirements into the new MOD-029.<br>R14. The SDT will consider this comment as it develops the next version of the standards. | |
| WECC ATC Team | Yes. The drafting team should be encouraged to include in the MOD-01 a formula describing how AFC is converted into ATC for the subsequent posting of ATC by those entities utilizing AFC.<br><br>"The Commission also required each transmission provider using an Available Flowgate Capacity (AFC) methodology to explain its definition of AFC, its calculation methodology and assumptions, and its process for converting AFC into ATC." P. 189.<br>R3. This requirement states that the TSP "…shall, when requested, provide or make available, the following values…" What is the retention period for the TSP such that the data will still be available when requested? The drafting team should modify this requirement such that the TSP is only required to respond to requests for data that are within the time frames established within their filed Tariff. For example, TSP's should not have to provide ATC values that would require a System Impact Study.<br>R3. & R6. This requirement states that the TSP provide certain data when requested and when the requestor "…has a reliability related need for the values." How does the TSP judge whether the requester has a reliability related need or not? The drafting team needs to establish a criterion for the need or strike this phrase from the requirement. |

| Question #19 | |
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| **Commenter** | **Comment** |
| | R11.2 & R11.3 This requirement states that TSP's, "Require that the calculation of ATC or AFC use the same criteria and assumptions used to conduct reliability assessment and internal expansion planning for different time frames etc." and that they "Document the criteria used for calculating ATC or AFC values for the different time frames etc. and the rationale for any differences between these."<br><br>Those TSPs who use the Rated System Path Methodology rely heavily on criteria and assumptions for calculating the TTC for a path but not for the calculation of ATC. Once the TTC for a path is determined the determination of ATC is simple math with little concern for criteria or assumptions.<br><br>We recommend that the drafting team restrict these two requirements to those TSP's who use the AFC Calculation Methodology and create a parallel requirement for the calculation of TTC for those TSP's who use the Rated System Path Methodology.<br><br>R11.4 & R11.5 This requirement states that TSP's must "Identify the contingencies considered in the ATC and AFC calculation methodologies." and that they "..use the same power flow models, and the same assumptions regarding load, generation dispatch, special protection systems etc. as those used in the expansion planning for the same time frames." This would be important for those who use the AFC Calculation Methodology and build power flow models to determine if capacity will be available. For those using the Rated System Path Methodology these factors are important for the determination of TTC but not for the determination of ATC. Rated System Path Methodology users do not build power flow cases and study contingencies to determine "ATC"; rather, these case studies are done to determine the TTC rating of paths. Therefore we recommend that the drafting team restrict these two requirements to those TSP's who use the AFC Calculation Methodology and create a parallel requirement for the calculation of TTC for those TSP's who use the Rated System Path Methodology.<br><br>R12. This requirement states that TSP's must "Identify the Transmission Service Providers with which the data used in the calculation of ATC or AFC is exchanged." Coordination of data is important but for those using the Rated System Path Methodology this coordination takes place when the TTC for the path and not the ATC for the path is calculated. We recommend that the drafting team make this requirement apply only to those using the AFC Methodology in MOD 001 and create a comparable requirement in the TTC calculation standard for those using the Rated System Path Methodology.<br><br>R14. This requirement states that "The Transmission Service Provider shall require that the Transmission Customer provide both ultimate source and ultimate sink on the Transmission Service Request and shall require that the Transmission Customer use the same source and sink on Interchange Transaction Tags."<br><br>The WECC Team suggests this Requirement should be applicable only to entities using the AFC methodology. |

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|---|---|
| **Commenter** | **Comment** |
| | For entities using the Rated System Path (re: the majority of WECC) the source and sink are already part of the Tagging system. At minimum that makes the Requirement redundant for the Rated System Path participants. Further, since Tagging is a business practice, this requirement would fall into the purview of NEASB. Lastly, unlike those using the AFC methodology, the source and sink of each request and subsequent schedule is not needed to determine ATC as it is for those determining AFC using Flowgates. Since entities calculating AFC need to know the source and sink for Flowgate modeling purposes (whereas those using the Rated System Path method do not), the logical application for this Requirement is to those using the AFC methodology. |

**Response:**
Please see the proposed MOD-030 – this standard does include requirements to convert AFC to ATC.
Order 693, P. 1031 / issued after the Standard was drafted states, "Accordingly, transmission providers using an AFC methodology must convert flowgate (AFC) values into path (ATC) values for OASIS posting. See also Order 890, P. P. 211
R3. The revised standard does not include R3.
R6 The SDT agrees it may need to establish a criterion for the "reliability need for the values" or strike this phrase from the requirement. The next draft of the standard will address this.
R11.The revised MOD-001 only includes 'generic' ATC requirements – the requirements for each of the three different methods of calculating ATC have been moved into separate standards, and each of the separate standards includes much more specificity than had been included in MOD-001. Please review MOD-028, MOD-029 and MOD-030.

R12: The revised MOD-001 requires the TSP to develop a document called "Available Transfer Capability Implementation Document" and this document must contain the names of the TSPs with which the TSP exchanges data for use in determining ATC.
R14: The drafting team removed this requirement. Order 890 requires NERC to develop requirements in MOD-001 that specify "a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown" so there will be a requirement that addresses sources and sinks and how they are to be consistently modeled (simulated). The drafting team will consider moving the tagging requirement to a NAESB practice.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Standard Authorization Request Form

| | |
|---|---|
| Title of Proposed Standard: Revisions to existing Standards MOD-001 through MOD-009; FAC-012 through FAC-013. (This SAR is intended to supplement the two already approved SARs for "Revision to Existing Standard MOD-001" dated 2/15/2006 and "Revision to Standards MOD-004, MOD-005, MOD-006, MOD-008, MOD-009" ) | |
| Request Date: | May 23, 2007 |

| **SAR Requester Information** | **SAR Type** (*Check a box for each one that applies.*) | |
|---|---|---|
| Name: The following members of the ATCT Drafting Team:<br>Larry Middleton<br>Chuck Falls<br>Ross Kovacs<br>Laura Lee<br>Cheryl Mendrala<br>Nate Schweighart | ☐ | New Standard |
| Primary Contact: Laura Lee | ☒ | Revision to existing Standard |
| Telephone: (704) 382-3625<br>Fax: | ☒ | Withdrawal of existing Standard (possible) |
| E-mail: | ☐ | Urgent Action |

**Purpose**

This SAR is intended to supplement the SAR for "Revision to Existing Standard MOD-001" dated 2/15/2006, in response to FERC Orders 890 and 693. In evaluating the Orders, it has been discovered that additional modifications will be required to ensure clarity and consistency. Specifically, the following Standards may be modified, transferred to NAESB, or retired:

FAC-012 Transfer Capability Methodology
FAC-013 Establish and Communicate Transfer Capabilities
MOD-002 Review of TTC and ATC Calculations and Results
MOD-003 Procedure for Input on TTC and ATC Methodologies and Values
MOD-007 Documentation of the Use of CBM

**Industry Need** The FERC has directed NERC to provide these changes and clarifications in support of Preventing Undue Discrimination and Preference in Transmission Service, as well in support of Mandatory Reliability Standards for the Bulk Power System.

NERC, as the ERO is required to comply with all FERC directives.

**Brief Description** As directed by the FERC, the drafting team is developing proposed requirements to bring greater consistency and transparency to the calculation of TTC/TFC, ATC/AFC, ETC, CBM, and TRM. The modifications include elimination of the 'fill-in-the-blank' requirements. This possibility was identified in the original SAR; this supplemental SAR is requesting explicit ability to take action on these other standards as a part of the entire standards effort.

**Detailed Description**

Actions of the drafting team may include:

- FAC-012 Transfer Capability Methodology
  - Retirement and movement to a new MOD standard. These standards are not related to Facility Design, Construction, and Maintenance. Rather, they are about the mathematical constructs used to analyze the bulk electric system for the purposes o maintaining reliability.
- FAC-013 Establish and Communicate Transfer Capabilities
  - Incorporation into the new MOD standard and retirement. These standards are not related to Facility Design, Construction, and Maintenance. Rather, they are about the mathematical constructs used to analyze the bulk electric system for the purposes o maintaining reliability.
- MOD-002 Review of TTC and ATC Calculations and Results
  - Incorporation into MOD-001 and retirement. It is believed that much of this is related to the measurement and compliance aspects of Available Transfer Capability, and will be handled as such.
- MOD-003 Procedure for Input on TTC and ATC Methodologies and Values
  - Transfer to NAESB and retirement. It is believed that this standard is more focused on business practices.
- MOD-007 Documentation of the Use of CBM
  - Incorporation into MOD-004 and retirement. It is believed that much of this is related to the measurement and compliance aspects of CBM, and will be handled as such.

The drafting team will address all of the directives in FERC Order 693 and FERC Order 890 listed in Attachment 1.

***Reliability Functions***

| **The Standard will Apply to the Following Functions** *(Check box for each one that applies.)* | | |
|---|---|---|
| ☒ | Reliability Coordinator | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view. |
| ☒ | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time. |
| ☐ | Interchange Coordinator | Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas. |
| ☒ | Planning Coordinator | Assesses the longer-term reliability of its Planning Coordinator Area. |
| ☐ | Resource Planner | Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area. |
| ☒ | Transmission Planner | Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area. |
| ☒ | Transmission Service Provider | Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff). |
| ☒ | Transmission Owner | Owns and maintains transmission facilities. |
| ☒ | Transmission Operator | Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area. |
| ☐ | Distribution Provider | Delivers electrical energy to the End-use customer. |
| ☒ | Generator Owner | Owns and maintains generation facilities. |
| ☐ | Generator Operator | Operates generation unit(s) to provide real and reactive power. |
| ☒ | Purchasing-Selling Entity | Purchases or sells energy, capacity, and necessary reliability-related services as required. |
| ☐ | Market Operator | Interface point for reliability functions with commercial functions. |
| ☒ | Load-Serving Entity | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view. |

***Reliability and Market Interface Principles***

| **Applicable Reliability Principles** *(Check box for all that apply.)* | |
|---|---|
| ☒ | 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☒ | 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☐ | 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented. |
| ☐ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems. |
| ☒ | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis. |
| ☐ | 8. Bulk power systems shall be protected from malicious physical or cyber attacks. |

| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box.)* |
|---|
| 1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

***Related Standards***

| Standard No. | Explanation |
|---|---|
| None | None |
| | |
| | |
| | |

***Related SARs***

| SAR ID | Explanation |
|---|---|
| None | None |
| | |
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***Regional Variances***

| Region | Explanation |
|---|---|
| ERCOT | None |
| FRCC | None |
| MRO | None |
| NPCC | None |
| SERC | None |
| RFC | None |
| SPP | None |
| WECC | None |

**Directives from Order 693 and 890 related to ATC Standards**

693-1057 Develop non-fill-in-the-blank Standard
693-1057 Define information to be shared between TSPs for ATC calculations
693-1057 Planning Assumptions and ATC Assumptions should be the same
890-292 Planning Assumptions and ATC Assumptions should be the same
890-292 Load levels the same plan/ops vs. ATC
890-292 Gen Dispatch the same plan/ops vs. ATC
890-292 TX and Gen Facilities maintenance the same plan/ops vs. ATC
890-292 Contingency outages the same plan/ops vs. ATC
890-292 Topology the same plan/ops vs. ATC
890-292 TX Reservations the same plan/ops vs. ATC
890-292 Assumptions re: additions and retirements the same plan/ops vs. ATC
890-292 Counter-flows the same plan/ops vs. ATC
890-295 Load level modeling methodology the same
890-296 Dispatch should include all DNRs and committed resources as expected to run, and uncommitted resources deliverable within CA, economically dispatched to meet balancing needs
890-297 How to model POR to POD without source/sink
890-297 How to model existing reservations
693-1057 ATC should be updated on a consistent schedule
693-1057 ATC/TTC Assumptions and Contingencies must be made available
693-1057 Put TTC in FAC section
693-1057 Identify applicable entities
693-1105 CBM must be 0 in non-firm ATC
890-262 CBM =0 in Non-Firm Calc
890-273 TRM <> =0 in Non-Firm Calc
890-211 Standard AFC->ATC Calculation
890-212 Firm ATC uses only Firm Commitments
890-212 Non-Firm ATC uses firm and non-firm commitments, post-backs or redirected services, unscheduled service, and counter-flows
890-237 Address differences between Pro-Forma TTC and Native Load/Reliability Assessment TTC
890-243 Standard calc of native load use - include in MOD-001
890-244 ETC = Native load (including Network)
890-244 ETC = Grandfathered
890-244 ETC = Appropriate PTP
890-244 ETC = Long-term Rollover rights
890-244 Define any additional ETC components
890-245 Reservations with Same POR whose SUM would exceed gen nameplate must be addressed
890-310 Mandatory Data Exchange for ATC
890-310 DEX Load
890-310 DEX TX Plan and Contingency outages
890-310 DEX Gen Plan and Contingency outages
890-310 DEX Base dispatch
890-310 DEX existing reservations including counter-flows
890-310 DEX ATC recalculation frequencies and times
890-310 DEX Source sink modeling identification
890=389 Unscheduled Reservation released on non-firm and posted on OASIS

**Directives from Order 693 and 890 related to CBM Standard**

693-1082 CBM set aside at verified request of LSE
693-1082 Require disclosure of CBM studies
693-1082 Define flowgate/path allocation process for CBM
693-1082 No double counting
693-1082 Add LSE, BA as applicable entity where necessary
693-1105 CBM Must be used only for generation deficiencies
693-1105 Generation Deficiency must be states as an EEA level
890-260 Define flowgate/path allocation process for CBM
890-262 CBM Must be used only for generation deficiencies
890-358 yearly CBM studies
693-1081 What to do if CBM exceeds ATC?

**Directives from Order 693 and 890 related to TRM Standard**

693-1122 Define flowgate/path allocation process for TRM
693-1126 Explicit definition of what goes into TRM
693-1122 TRM = Load Forecast and Load Distribution Error
693-1122 TRM = Variation in facility loading
693-1122 TRM = uncertainty in transmission topology
693-1122 TRM = loop flow
693-1122 TRM = variations in dispatch
693-1122 TRM = ARS
693-1122 Define any additional uses
890-273 Explicit definition of what goes into TRM
890-273 TRM = Load Forecast and Load Distribution Error
890-273 TRM = Variation in facility loading
890-273 TRM = uncertainty in tx topology
890-273 TRM = loop flow
890-273 TRM = variations in dispatch
890-273 TRM = ARS
890-273 Define any additional uses
693-1082 No double counting
890-273 No double counting
693-1126 Max TRM Calc
890-275 Max TRM Calc
693-1126 Standard on How TRM to be calculated
693-1126 Add PC, RE to applicable entities

**Maureen E. Long**
Standards Process Manager

May 25, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

## Announcement: Comment Period Opens

**The Standards Committee (SC) announces the following standards actions:**

### SAR and Draft Standards for Available Transfer Capability (Project 2006-07) Posted for 30-day Comment Period May 25–June 24, 2007

To fully address the directives in FERC Orders 890 and 693 relative to Available Transfer Capability (ATC), a "Supplemental ATC SAR" has been posted for a 30-day comment period. Please use the comment form to provide comments on this SAR.

The ATC Standard Drafting Team has posted a set of requirements distributed amongst six standards aimed at meeting the intent of the originally approved SARs for ATC/TTC/AFC and CBM/TRM as well as the directives in FERC Orders 890 and 693. The drafting team also posted a white paper that explains the following proposed organization of the revised set of standards:

- There is one "umbrella" standard with requirements related to ATC (MOD-001 and comment form)
- There are three separate standards to address the determination of ATC, with each also addressing associated requirements for TTC and ETC:
  - Network Response method of calculating ATC (MOD-028 and comment form)
  - Rated System Path method of calculating ATC (MOD-029 and comment form)
  - Flowgate Network Response method of calculating ATC (MOD-030 and comment form)
- There is a separate standard to address Capacity Benefit Margin (MOD-004 and comment form)
- There is a separate standard to address Transmission Reliability Margin (MOD-008 and comment form).

Because the modifications made to the standards are so extensive, no "redline" versions of the standards have been developed. The versions of the standards that have been posted contain only requirements — there are no measures or compliance elements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please use the comment forms posted with the proposed standards to provide comments on this set of standards.

## Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Please use this form to submit comments on the proposed Supplemental SAR for Revisions to MOD-001 through MOD-009; FAC-012 through FAC-013. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "ATC Supplement SAR" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

This SAR is intended to supplement the already approved SARs to modify ATC/TTC/AFC and CBM/TRM. The expanded scope will bring the set of standards into compliance with the latest versions of the Reliability Standards Procedure Manual and the ERO's Sanctions Guidelines and will address the directives relative to ATC in FERC Orders 890 and 693.

In addition to making all required modifications to MOD-001, MOD-004, and MOD-008, the following standards may be modified, transferred to NAESB, or retired in accordance with stakeholder comments and FERC directives:

FAC-012 – Transfer Capability Methodology
FAC-013 – Establish and Communicate Transfer Capabilities
MOD-002 – Review of TTC and ATC Calculations and Results
MOD-003 – Procedure for Input on TTC and ATC Methodologies and Values
MOD-007 – Documentation of the Use of CBM

The requesters would like to receive industry comments on this SAR. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "ATC Supplement SAR" by **June 24, 2007**.

**You do not have to answer all questions.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. NERC must address the directives in FERC Orders 890 and 693. Do you agree that this SAR is comprehensive enough to fully address the directives relative to ATC that are included in these Orders? If not, please explain in the comments area.

   ☐ Yes

   ☐ No

   Comments:

2. Please provide any other comments you have on the SAR.

   Comments:

Please return this form to sarcomm@nerc.net by **June 8, 2007** with "ATC Supplement Nomination" in the subject line. For questions, please contact Andy Rodriquez at 609-947-3885 or Andy.Rodriquez@nerc.net.

| | |
|---|---|
| Name: | |
| Organization: | |
| Address: | |
| Office Telephone: | |
| E-mail: | |
| **Please briefly describe your experience and qualifications to serve on the ATC Standard Drafting Team. Prefer engineers, analysts, or other industry experts with experience in the determination of Total Transfer Capability and Total Flowgate Capability in the planning and operating horizons. Previous experience working on or applying NERC or IEEE standards is beneficial, but not a requirement.** | |

| **I represent the following NERC Reliability Region(s) (check all that apply):** | | **I represent the following Industry Segment (check one):** |
|---|---|---|
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
| ☐ FRCC | ☐ | 2 — RTOs, ISOs |
| ☐ MRO | ☐ | 3 — Load-serving Entities |
| ☐ NPCC | ☐ | 4 — Transmission-dependent Utilities |
| ☐ RFC | ☐ | 5 — Electric Generators |
| ☐ SERC | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ SPP | ☐ | 7 — Large Electricity End Users |
| ☐ WECC | ☐ | 8 — Small Electricity End Users |
| ☐ NA – Not Applicable | ☐ | 9 — Federal, State, and Provincial Regulatory or other Government Entities |
| | ☐ | 10 – Regional Reliability Organizations and Regional Entities |

**Which of the following Function(s)[1] do you have expertise or responsibilities:**

| | |
|---|---|
| ☐ Reliability Coordinator | ☐ Transmission Service Provider |
| ☐ Balancing Authority | ☐ Transmission Owner |
| ☐ Interchange Authority | ☐ Load Serving Entity |
| ☐ Planning Coordinator | ☐ Distribution Provider |
| ☐ Transmission Operator | ☐ Purchasing-selling Entity |
| ☐ Generator Operator | ☐ Generator Owner |
| ☐ Transmission Planner | ☐ Resource Planner |
| | ☐ Market Operator |

**Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.**

| | |
|---|---|
| Name: | Office Telephone: |
| Organization: | E-mail: |
| Name: | Office Telephone: |
| Organization: | E-mail: |

[1] These functions are defined in the Functional Model, which is downloadable from the following Web site: http://www.nerc.com/~filez/functionalmodel.html

Please use this form to submit comments on the proposed Supplemental SAR for Revisions to MOD-001 through MOD-009; FAC-012 through FAC-013. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "ATC Supplement SAR" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: E. Nick Henery | | |
| Organization: APPA | | |
| Telephone: 202-467-2985 | | |
| E-mail: nhenery@APPAnet.org | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☒ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** APPA

**Lead Contact:** **E. Nick Henery**

**Contact Organization:** **APPA**

**Contact Segment:** **Segment 1**

**Contact Telephone:** **202-467-2985**

**Contact E-mail:** **nhenery@APPAnet.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Matt Schull | North Carolina Municipal Power Agency #1 | **SERC** | Segment 5 - Electric Generators |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

This SAR is intended to supplement the already approved SARs to modify ATC/TTC/AFC and CBM/TRM. The expanded scope will bring the set of standards into compliance with the latest versions of the Reliability Standards Procedure Manual and the ERO's Sanctions Guidelines and will address the directives relative to ATC in FERC Orders 890 and 693.

In addition to making all required modifications to MOD-001, MOD-004, and MOD-008, the following standards may be modified, transferred to NAESB, or retired in accordance with stakeholder comments and FERC directives:

FAC-012 – Transfer Capability Methodology
FAC-013 – Establish and Communicate Transfer Capabilities
MOD-002 – Review of TTC and ATC Calculations and Results
MOD-003 – Procedure for Input on TTC and ATC Methodologies and Values
MOD-007 – Documentation of the Use of CBM

The requesters would like to receive industry comments on this SAR. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "ATC Supplement SAR" by **June 24, 2007**.

**You do not have to answer all questions.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. NERC must address the directives in FERC Orders 890 and 693. Do you agree that this SAR is comprehensive enough to fully address the directives relative to ATC that are included in these Orders? If not, please explain in the comments area.

   ☐ Yes

   ☒ No

   Comments: The Supplemental SAR is incomplete and vague in directing the SDT as to its objective in providing new standards that will insure and/or improve the reliability of the BES.

2. Please provide any other comments you have on the SAR.

   Comments: The Following attach file contains modified versions of the Supplemental SAR sections that explains in detail the objective of the Supplemental SAR. These are recommended changes to SAR. See the Attached File with the recommended Changes.

Please use this form to submit comments on the proposed Supplemental SAR for Revisions to MOD-001 through MOD-009; FAC-012 through FAC-013. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "ATC Supplement SAR" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Greg Rowland | | |
| Organization: Duke Energy | | |
| Telephone: 704-382-5348 | | |
| E-mail: gdrowlan@duke-energy.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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In addition to making all required modifications to MOD-001, MOD-004, and MOD-008, the following standards may be modified, transferred to NAESB, or retired in accordance with stakeholder comments and FERC directives:

FAC-012 – Transfer Capability Methodology
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**You do not have to answer all questions.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. NERC must address the directives in FERC Orders 890 and 693. Do you agree that this SAR is comprehensive enough to fully address the directives relative to ATC that are included in these Orders? If not, please explain in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Please provide any other comments you have on the SAR.

   Comments:

Please use this form to submit comments on the proposed Supplemental SAR for Revisions to MOD-001 through MOD-009; FAC-012 through FAC-013. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "ATC Supplement SAR" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Dave Folk | |
| Organization: | FirstEnergy Corp. | |
| Telephone: | 330-384-4668 | |
| E-mail: | folkd@firstenergycorp.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☒ | 5 — Electric Generators |
| ☐ **SERC** | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
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   ☒ Yes

   ☐ No

   Comments: While the summary of FERC Directives contained on pages SAR-6 and SAR-7 appears very complete, the summary uses a shorthad notation that it is somewhat cryptic and difficult to decypher. However, there appear to have been some ommissions as follows:
   890-237 Consistent practices for calculating TTC/TFC
   890-244 In short-term ATC calclulations all reserved but unused transfer capability shall be released as non-firm ATC
   890-257 Develop standards for CBM determination, allocation and use
   890-259 CBM only used to allow LSE to meet its generation reliaibility criteria
   890-293 Approach for accounting for counter flows in ATC standards
   890-301 ATC recalculation by TSP on a consistent time interval and in a manner tha closely reflects actual system topology
   890-354 Unused transfer capability set aside for CBM made available for non-firm use and posted on OASIS
   890-416 Posting of load data on LSE or BAA level of granularity rather than RTO/ISO total load

2. Please provide any other comments you have on the SAR.

   Comments: Page SAR-2 paragraph FAC-012 and FAC-013 have misspellings "purposes o maintaining" should say "purpose of maintaining."

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| Organization: Hydro-Québec TransÉnergie | | |
| Telephone: 514 289-2211, X 2766 | | |
| E-mail: champagne.roger.2@hydro.qc.ca | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Danielle Beaulieu | Hydro-Québec TransÉnergie | **NPCC** | 1 |
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1. NERC must address the directives in FERC Orders 890 and 693. Do you agree that this SAR is comprehensive enough to fully address the directives relative to ATC that are included in these Orders? If not, please explain in the comments area.

   ☒ Yes

   ☒ No

   Comments: The SAR will address all of the 77 directives from Orders 693 and 890 that are listed in Attachment 1. It is not clear if this list is comprehensive. Does the list include references have already been handled in the MOD standards currently under review, or does the list only included references yet to be addressed?

2. Please provide any other comments you have on the SAR.

   Comments: Is it possible that the proposed SAR drafting team will revise the standards MOD-001, MOD-004, MOD-008, MOD-028, MOD-029 and MOD-030 that are currently under review?

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| **Individual Commenter Information** | | |
|---|---|---|
| **(Complete this page for comments from one organization or individual.)** | | |
| Name: | Ron Falsetti | |
| Organization: | IESO | |
| Telephone: | 905-855-6187 | |
| E-mail: | ron.falsetti@ieso.ca | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☒ Yes

   ☒ No

   Comments: The SAR proposes to address all of the 77 directives from Orders 693 and 890 that are listed in Attachment 1. However, it is not clear if this list is comprehensive. Does the list include references have already been handled in the MOD standards which are currently under review (MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1) or does the list only included those references which are not addressed by the above-mentioned standards under review currently?

2. Please provide any other comments you have on the SAR.

   Comments: Is it possible that the proposed SAR drafting team will revise the standards MOD-001, MOD-004, MOD-008, MOD-028, MOD-029 and MOD-030 that are currently under review? It might have been better that this SAR was addressed first and then the mentioned MOD standards if these were to be revised as a result of this supplemental SAR.

   We do not agree with making the MOD-004 standard, a cluttered standard. This coupled with the need to make a distinction between the ATC calculation methods used and the descriptive procedure for resource adequacy assessment has made the new MOD-004 very convoluted, and the requirements difficult to follow and measure. If combining some standards of related objective is desired, a more manageable and appropriate alternative is to divide these 4 standards into two groups - one on the determining and verifying the calculation of CBM (Methodology, Assumptions, and Documentation) and the other on the use and reporting of use of CBM (Applicability and Reporting).

   The roles of the Reliability Coordinator, Planning Coordinator, Transmission Owner, and the Transmission Service Provider must be clearly articulated in these standards as well as the new MOD standard that will come into effect as a result of FAC-012 and FAC-013.

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|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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|---|---|
| Group Comments (Complete this page if comments are from a group.) | |
| **Group Name:** | IRC Standards Review Committee |
| **Lead Contact:** | **Charles Yeung** |
| **Contact Organization:** | **SPP** |
| **Contact Segment:** | **2** |
| **Contact Telephone:** | **823-724-6142** |
| **Contact E-mail:** | **cyeung@spp.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Jim Castle | NYISO | **NPCC** | 2 |
| Alicia Daugherty | PJM | **RFC** | 2 |
| Ron Falsetti | IESO | **NPCC** | 2 |
| Matt Goldberg | ISO-NE | **NPCC** | 2 |
| Brent Kingsford | CAISO | **WECC** | 2 |
| Steve Myers | ERCOT | **ERCOT** | 2 |
| Anita Lee | AESO | **WECC** | 2 |
| Bill Phillips | MISO | **RFC+** | 2 |
| | | **MRO+** | |
| | | **SERC+** | |
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1. NERC must address the directives in FERC Orders 890 and 693. Do you agree that this SAR is comprehensive enough to fully address the directives relative to ATC that are included in these Orders? If not, please explain in the comments area.

   ☐ Yes

   ☒ No

   Comments: We agree that the SAR is comprehensive in addressing the FERC directives, and that changes to the MOD standards must be made to comply with the directives. However, this SAR is not comprehensive enough to provide the rationale and proposed scope and description on the restructuring of MOD-001, viz. the creation of MOD-028, MOD-029 and MOD-030, and more importantly, the retirement of FAC-012 and -013. And the revised SAR has not gone through a review and comment period before the newly created MOD-028, etc. are posted for comments.

   The proposed restructuring of MOD-001, the creation of new standards and the retirement of FAC Standards are substantive changes to the original SAR. As such, the rationale and details need to be provided to the revised SAR and posted for comment. The industry needs to be given an opportunity to comment on the need and appropriateness of spliting the standards in this fashion, and the scope of each of the split standards.

   The industry is now asked to comment both on the SAR and the revised and new MOD standards, which in our view makes commenting on the SAR as relates to the development of new MOD Standards almost irrelevant.

2. Please provide any other comments you have on the SAR.

   Comments: From a process viewpoint, 3 new standards are created, and two standards are considered to be retired, without a SAR. This SAR that we are commenting on only provides the basis for making changes to address FERC directives, but does not list and provide the rationale for the new standards or the retirement of standards. This doesn't seem to be consistent with the reliability standards development procedure.

   Similarly, there is no SAR or any mention in this SAR to combine MOD-004 to MOD-007. This is also a major change to the existing standards. A SAR to provide the rationale for the change, and the proposed scope of the consolidated standard need to be provided for industry comment, with sufficient time before any standard drafting work is done and the revised standards posted.

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Brian Thumm | |
| Organization: | ITC | |
| Telephone: | 248-374-7846 | |
| E-mail: | bthumm@itctransco.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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1. NERC must address the directives in FERC Orders 890 and 693. Do you agree that this SAR is comprehensive enough to fully address the directives relative to ATC that are included in these Orders? If not, please explain in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Please provide any other comments you have on the SAR.

   Comments: This SAR appears to be necessary to inform FERC of potential inconsistencies in the propose standards that might be caused by a small number of the FERC orders. TTC for AFC/ATC does not belong in FAC-012 for example, even though FERC directed this. It's based on a misunderstanding of the original intent of FAC-012. As such, we support any work to clarify the meaning and intent of standards that are needed to meet FERC orders.

Please use this form to submit comments on the proposed Supplemental SAR for Revisions to MOD-001 through MOD-009; FAC-012 through FAC-013. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "ATC Supplement SAR" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Michelle Rheault | |
| Organization: | Manitoba Hydro | |
| Telephone: | 204-487-5445 | |
| E-mail: | mdrheault@hydro.mb.ca | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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| ☐ **SERC** | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

This SAR is intended to supplement the already approved SARs to modify ATC/TTC/AFC and CBM/TRM. The expanded scope will bring the set of standards into compliance with the latest versions of the Reliability Standards Procedure Manual and the ERO's Sanctions Guidelines and will address the directives relative to ATC in FERC Orders 890 and 693.

In addition to making all required modifications to MOD-001, MOD-004, and MOD-008, the following standards may be modified, transferred to NAESB, or retired in accordance with stakeholder comments and FERC directives:

FAC-012 – Transfer Capability Methodology
FAC-013 – Establish and Communicate Transfer Capabilities
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MOD-003 – Procedure for Input on TTC and ATC Methodologies and Values
MOD-007 – Documentation of the Use of CBM

The requesters would like to receive industry comments on this SAR. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "ATC Supplement SAR" by **June 24, 2007**.

**You do not have to answer all questions.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. NERC must address the directives in FERC Orders 890 and 693. Do you agree that this SAR is comprehensive enough to fully address the directives relative to ATC that are included in these Orders? If not, please explain in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Please provide any other comments you have on the SAR.

   Comments:

Please use this form to submit comments on the proposed Supplemental SAR for Revisions to MOD-001 through MOD-009; FAC-012 through FAC-013. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "ATC Supplement SAR" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** | | |
|---|---|---|
| **(Complete this page for comments from one organization or individual.)** | | |
| Name: | Tom Mielnik | |
| Organization: | MidAmerican Enery Company | |
| Telephone: | 563-333-8129 | |
| E-mail: | tcmielnik@midamerican.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☒ **MRO** | ☒ | 3 — Load-serving Entities |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☒ Yes

   ☐ No

   Comments:

2. Please provide any other comments you have on the SAR.

   Comments: I have no comment except to commend the Standards Drafting Team on doing a good job at developing the supplemental SAR and the revised standards to incoporate the FERC Orders. While I have comments on them, these revised standards as well as the supplemental SAR gets the NERC well on the way to responding to the FERC orders.

Please use this form to submit comments on the proposed Supplemental SAR for Revisions to MOD-001 through MOD-009; FAC-012 through FAC-013. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "ATC Supplement SAR" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

<table>
<tr><th colspan="3">Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☐ NPCC<br>☐ RFC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
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<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

| Group Comments (Complete this page if comments are from a group.) | | | |
|---|---|---|---|
| **Group Name:** | Midwest Reliability Organization (MRO) | | |
| **Lead Contact:** | **Tom Mielnik** | | |
| **Contact Organization:** | **MRO for Group (MEC - for lead contact)** | | |
| **Contact Segment:** | **10** | | |
| **Contact Telephone:** | **563-333-8129** | | |
| **Contact E-mail:** | **tcmielnik@midamerican.com** | | |
| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
| Neal Balu | WPS | **MRO** | 10 |
| Terry Bilke | MISO | **MRO** | 10 |
| Robert Coish, Chair | MHEB | **MRO** | 10 |
| Carol Gerou | MP | **MRO** | 10 |
| Ken Goldsmith | ALT | **MRO** | 10 |
| Todd Gosnell | OPPD | **MRO** | 10 |
| Jim Haigh | WAPA | **MRO** | 10 |
| Joe Knight | GRE | **MRO** | 10 |
| Pam Oreschnick | XEL | **MRO** | 10 |
| Dave Rudolph | BEPC | **MRO** | 10 |
| Eric Ruskamp | LES | **MRO** | 10 |
| Mike Brytowski, Secretary | MRO | **MRO** | 10 |
| 28 Additional MRO Members | Not Named Above | **MRO** | 10 |
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   ☒ Yes

   ☐ No

   Comments:

2. Please provide any other comments you have on the SAR.

   Comments: The MRO has no comment except to commend the Standards Drafting Team on doing a good job at developing the supplemental SAR and the revised standards to incoporate the FERC Orders. While the MRO has comments on them, these revised standards as well as the supplemental SAR gets the NERC well on the way to responding to the FERC orders.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| Group Comments (Complete this page if comments are from a group.) | |
|---|---|
| **Group Name:** | NPCC CP9 Reliability Standards Working Group |
| **Lead Contact:** | **Guy V. Zito** |
| **Contact Organization:** | **NPCC** |
| **Contact Segment:** | **10** |
| **Contact Telephone:** | **212-840-1070** |
| **Contact E-mail:** | **gzito@npcc.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Kathleen Goodman | ISO-New England | **NPCC** | 2 |
| Roger Champagne | HydroQuebec TranEnergie | **NPCC** | 1 |
| Greg Campoli | New York ISO | **NPCC** | 2 |
| Al Adamson | New York State Reliability Council | **NPCC** | 10 |
| Guy V. Zito | NPCC | **NPCC** | 10 |
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   ☒ Yes

   ☒ No

   Comments: The SAR will address all of the 77 directives from Orders 693 and 890 that are listed in Attachment 1. It is not clear if this list is comprehensive. Does the list include references have already been handled in the MOD standards currently under review, or does the list only included references yet to be addressed?

2. Please provide any other comments you have on the SAR.

   Comments: Is it possible that the proposed SAR drafting team will revise the standards MOD-001, MOD-004, MOD-008, MOD-028, MOD-029 and MOD-030 that are currently under review?

Please use this form to submit comments on the proposed Supplemental SAR for Revisions to MOD-001 through MOD-009; FAC-012 through FAC-013. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "ATC Supplement SAR" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

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| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | Public Service Commission of South Carolina |
| **Lead Contact:** | **Phil Riley** |
| **Contact Organization:** | **Public Service Commission of South Carolina** |
| **Contact Segment:** | **9** |
| **Contact Telephone:** | **803-896-5154** |
| **Contact E-mail:** | **philip.riley@psc.sc.gov** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mignon L. Clyburn | PSCSC | **SERC** | 9 |
| G. O'Neal Hamilton | PSCSC | **SERC** | 9 |
| John E. "Butch" Howard | PSCSC | **SERC** | 9 |
| Randy Mitchell | PSCSC | **SERC** | 9 |
| C. Robert "Bob" Moseley | PSCSC | **SERC** | 9 |
| David A. Wright | PSCSC | **SERC** | 9 |
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   ☒ Yes

   ☐ No

   Comments:

2. Please provide any other comments you have on the SAR.

   Comments:

# Standard Authorization Request Form

## Attachment to the Supplemental SAR

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| | |
|---|---|
| Title of Proposed Standard | Revisions to existing Standards MOD-001 through MOD-009; FAC-012 through FAC-013. (This SAR is intended to supplement the two already approved SARs for "Revision to Existing Standard MOD-001" dated 2/15/2006 and "Revision to Standards MOD-004, MOD-005, MOD-006, MOD-008, MOD-009" ) |
| Request Date | May 23, 2007 |

| SAR Requester Information | SAR Type (*Check a box for each one that applies.*) | |
|---|---|---|
| Name The following members of the ATCT Drafting Team: | ☐ | New Standard |
| Primary Contact | ☒ | Revision to existing Standard |
| Telephone<br>Fax | ☒ | Withdrawal of existing Standard (possible) |
| E-mail | ☐ | Urgent Action |

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**Purpose**

This SAR is intended to supplement the SAR for "Revision to Existing Standard MOD-001" dated 2/15/2006, in response to FERC Orders 890 and 693. In evaluating the Orders, it has been discovered that additional modifications will be required to ensure clarity and consistency. Specifically, the following Standards may be modified, transferred to NAESB, or retired:

FAC-012 Transfer Capability Methodology
FAC-013 Establish and Communicate Transfer Capabilities
MOD-002 Review of TTC and ATC Calculations and Results
MOD-003 Procedure for Input on TTC and ATC Methodologies and Values
MOD-007 Documentation of the Use of CBM

**Industry Need** The FERC has directed NERC to provide these changes and clarifications in support of Preventing Undue Discrimination and Preference in Transmission Service, as well in support of Mandatory Reliability Standards for the Bulk Power System. NERC and the Industry will provide these changes and clarifications in support of Consistent Modeling Methods and Principles for Simulating Power Transfers and Determination of Transfer Capabilities, Timely and Accurate Communication of the Values of the TTC/TFC and the Assumptions Used to Calculate the TTC/TFC, and eliminating a fill-in-the-blank Standards.

NERC, as the ERO, is required to comply with all FERC directives.

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**Brief Description** As directed by the FERC, the drafting team is developing proposed requirements to bring greater consistency and transparency to the calculation of TTC/TFC, ATC/AFC, ETC, CBM, and TRM. The modifications include elimination of the 'fill-in-the-blank' requirements. This possibility was identified in the original SAR; this supplemental SAR is requesting explicit ability to take action on these other standards as a part of the entire standards effort. This will be accomplished by the expansion of the exiting MOD-001 through 009 Standard Drafting Team. The expanded MOD-001 through 009 Standard Drafting Team will be comprised of personnel experienced and qualified in the calculation of the TTC/TFC for the planning and operating horizons and communicating those values and assumptions in a manner that will support the planning and operations of the BES and support efforts to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers.

**Detailed Description**

Actions of the drafting team may include:

FAC-012 Transfer Capability Methodology

Modification of FAC-012 or retirement of FAC-012 and movement to a new MOD standard. These standards are not related to Facility Design, Construction, and Maintenance. Rather, they are about the mathematical modeling used to analyze the bulk electric system for the purposes of maintaining reliable planning and operation of the BES and supporting efforts to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers. However, all of the FAC Standards series are relate and the modeling in Standard FAC -012 is directly related to FAC 001 through 011.

Prepare for approval by the Industry, NERC BOT, and FERC a detailed standard that will provide the necessary requirements for the industry to develop Total Transfer Capabilities or Total Flowgate Capabilities utilizing methods that will meet the following requirements:

- Eliminate the "fill-in-blank" format of FAC-012-1
- The Standard will be written in a detailed format that incorporates the principles of calculating Total Transfer Capabilities or Total Flowgate Capabilities contained in "A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems;" dated 1995; Titled Transmission Transfer Capability; published by the North American Electric Reliability Council.
- The Standard will be written to include detailed requirements for eliminating discontinuity at the seams between Regions that utilize different methods of calculating Total Transfer Capability or Total Flowgate Capabilities.
- The Standard will retire the glossary term Transfer Capability and modify, if necessary, the glossary term Total Transfer Capability to be consistent with the principles contained in the this Standard.
- The Standard will insure that the Applicable Reliability Functions calculate the values of the Total Transfer Capabilities or Total Flowgate Capabilities for planning and operating horizons in a timely manner that will support the planning and operations of the BES and support marketing effort to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers.

FAC-013 Establish and Communicate Transfer Capabilities

Modification of FAC-013 or retirement of FAC-013 and incorporation into a new MOD standard. These standards are not related to Facility Design, Construction, and Maintenance. Rather, they are about the mathematical modeling used to analyze the bulk electric system for the purposes of maintaining reliable planning and operation of the BES and supporting efforts to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers.

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Prepare for approval by the Industry, NERC BOT, and FERC a detailed standard that will provide the necessary requirements for the industry to timely communicate the values of the Total Transfer Capability or Total Flowgate Capability calculated in accordance with the requirements of FAC-012; and to communicate, when required by other Standards, the assumptions used to calculate the values of the Total Transfer Capability or Total Flowgate Capability to support reliable operations and the marketing requirements of Available Transfer Capability.

The assumptions used to determine the Total Transfer Capability or Total Flow Capability communicated to the industry shall, without violating confidentially or security requirements, include, but not be limited to:

- Existing Transmission Commitments Used for Planned Scheduled Energy Transfers
- Projected Loads
- Planned Generator Unit Commitments
- Planned System Configuration of the Interconnected System
- System Contingencies Assumed During the Studies
- Impacts of Neighboring Systems
- Impacts on Neighboring Systems

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MOD-002 Review of TTC and ATC Calculations and Results

Incorporation into MOD-001 and retirement. It is believed that much of this is related to the measurement and compliance aspects of Available Transfer Capability, and will be handled as such.

MOD-003 Procedure for Input on TTC and ATC Methodologies and Values

Transfer to NAESB and retirement. It is believed that this standard is more focused on business practices.

MOD-007 Documentation of the Use of CBM

Incorporation into MOD-004 and retirement. It is believed that much of this is related to the measurement and compliance aspects of CBM, and will be handled as such.

The drafting team will address all of the directives in FERC Order 693 and FERC Order 890 listed in Attachment 1.

***Reliability Functions***

| **The Standard will Apply to the Following Functions** *(Check box for each one that applies.)* | | |
|---|---|---|
| ☒ | Reliability Coordinator | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view. |
| ☒ | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time. |
| ☐ | Interchange Coordinator | Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas. |
| ☒ | Planning Coordinator | Assesses the longer-term reliability of its Planning Coordinator Area. |
| ☐ | Resource Planner | Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area. |
| ☒ | Transmission Planner | Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area. |
| ☒ | Transmission Service Provider | Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff). |
| ☒ | Transmission Owner | Owns and maintains transmission facilities. |
| ☒ | Transmission Operator | Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area. |
| ☐ | Distribution Provider | Delivers electrical energy to the End-use customer. |
| ☒ | Generator Owner | Owns and maintains generation facilities. |
| ☐ | Generator Operator | Operates generation unit(s) to provide real and reactive power. |
| ☒ | Purchasing-Selling Entity | Purchases or sells energy, capacity, and necessary reliability-related services as required. |
| ☐ | Market Operator | Interface point for reliability functions with commercial functions. |
| ☒ | Load-Serving Entity | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view. |

***Reliability and Market Interface Principles***

| **Applicable Reliability Principles** *(Check box for all that apply.)* | |
|---|---|
| ☒ | 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☒ | 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☐ | 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented. |
| ☐ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems. |
| ☒ | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis. |
| ☐ | 8. Bulk power systems shall be protected from malicious physical or cyber attacks. |

| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box.)* |
|---|
| 1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

***Related Standards***

| Standard No. | Explanation |
|---|---|
| None | None |
| | |
| | |
| | |

***Related SARs***

| SAR ID | Explanation |
|---|---|
| None | None |
| | |
| | |
| | |
| | |
| | |
| | |
| | |

***Regional Variances***

| Region | Explanation |
|---|---|
| ERCOT | None |
| FRCC | None |
| MRO | None |
| NPCC | None |
| SERC | None |
| RFC | None |
| SPP | None |
| WECC | None |

**Directives from Order 693 and 890 related to ATC Standards**

**693-782 Directs the ERO to modify FAC-012 to calculate transfer capability for ATC calculations and eliminate fill-in-the-blank format.**
**693-783 Recognized that the change for FAC-012 is on the schedule set in Order 890**
**693-1050 TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0.**
**693-1051 The Commission directs the ERO, through the Reliability Standards development process, to modify FAC-012-1 and any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the pro forma OATT,**

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693-1057 Develop non-fill-in-the-blank Standard
693-1057 Define information to be shared between TSPs for ATC calculations
693-1057 Planning Assumptions and ATC Assumptions should be the same
890-292 Planning Assumptions and ATC Assumptions should be the same
890-292 Load levels the same plan/ops vs. ATC
890-292 Gen Dispatch the same plan/ops vs. ATC
890-292 TX and Gen Facilities maintenance the same plan/ops vs. ATC
890-292 Contingency outages the same plan/ops vs. ATC
890-292 Topology the same plan/ops vs. ATC
890-292 TX Reservations the same plan/ops vs. ATC
890-292 Assumptions re: additions and retirements the same plan/ops vs. ATC
890-292 Counterlfows the same plan/ops vs. ATC
890-295 Load level modeling methodology the same
890-296 Dispatch should include all DNRs and committed resources as expected to run, and uncommitted resources deliverable within CA, economically dispatched to meet balancing needs
890-297 How to model POR to POD without source/sink
890-297 How to model existing reservations
693-1057 ATC should be updated on a consistent schedule
693-1057 ATC/TTC Assumptions and Contingencies must be made available
693-1057 Put TTC in FAC section
693-1057 Identify applicable entities
693-1105 CBM must be 0 in non-firm ATC
890-262 CBM =0 in Non-Firm Calc
890-273 TRM <> =0 in Non-Firm Calc
890-211 Standard AFC->ATC Calculation
890-212 Firm ATC uses only Firm Commitments
890-212 Non-Firm ATC uses firm and non-firm commitments, postbacks or redirected services, unscheduled service, and counterflows
890-237 Address differencess between Pro-Forma TTC and Native Load/Reliability Assessment TTC
890-243 Standard calc of native load use - include in MOD-001
890-244 ETC = Native load (including Network)
890-244 ETC = Grandfathered
890-244 ETC = Appropriate PTP
890-244 ETC = Long-term Rollover rights
890-244 Define any additional ETC components
890-245 Reservations with Same POR whose SUM would exceed gen nameplate must be addressed
890-310 Mandatory Data Exchange for ATC
890-310 DEX Load
890-310 DEX TX Plan and Contingency outages
890-310 DEX Gen Plan and Contingency outages

890-310 DEX Base dispatch
890-310 DEX existing reservations incl counterflows
890-310 DEX ATC recalc frequencies and times
890-310 DEX Source sink modeling identification
890=389 Unscheduled Reservation released on non-firm and posted on OASIS

| Directives from Order 693 and 890 related to CBM Standard |
|---|
| 693-1082 CBM set aside at verified request of LSE |
| 693-1082 Require disclosure of CBM studies |
| 693-1082 Define flowgate/path allocation process for CBM |
| 693-1082 No double counting |
| 693-1082 Add LSE, BA as applicable entity where necessary |
| 693-1105 CBM Must be used only for generation deficiencies |
| 693-1105 Generation Deficiency must be states as an EEA level |
| 890-260 Define flowgate/path allocation process for CBM |
| 890-262 CBM Must be used only for generation deficiencies |
| 890-358 yearly CBM studies |
| 693-1081 What to do if CBM exceeds ATC? |
| **Directives from Order 693 and 890 related to TRM Standard** |
| 693-1122 Define flowgate/path allocation process for TRM |
| 693-1126 Explicit definition of what goes into TRM |
| 693-1122 TRM = Load Forecast and Load Distribution Error |
| 693-1122 TRM = Variation in facility loading |
| 693-1122 TRM = uncertainty in transmission topology |
| 693-1122 TRM = loop flow |
| 693-1122 TRM = variations in dispatch |
| 693-1122 TRM = ARS |
| 693-1122 Define any additional uses |
| 890-273 Explicit definition of what goes into TRM |
| 890-273 TRM = Load Forecast and Load Distribution Error |
| 890-273 TRM = Variation in facility loading |
| 890-273 TRM = uncertainty in tx topology |
| 890-273 TRM = loop flow |
| 890-273 TRM = variations in dispatch |
| 890-273 TRM = ARS |
| 890-273 Define any additional uses |
| 693-1082 No double counting |
| 890-273 No double counting |
| 693-1126 Max TRM Calc |
| 890-275 Max TRM Calc |
| 693-1126 Standard on How TRM to be calculated |
| 693-1126 Add PC, RE to applicable entities |

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

**Consideration of Comments — (Supplemental) SAR for Revisions to Standards MOD-001 through MOD-009; FAC-012 through FAC-013**

The requesters thank all commenters who submitted comments on the (Supplemental) SAR for Revisions to Standards MOD-001 through MOD-009; FAC-012 through FAC-013. This SAR was posted for a 30-day public comment period from May 24 through June 25, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 12 sets of comments, including comments from 40 different people from more than 30 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team has made the following minor changes to the SAR and is recommending that the Standards Committee authorize the standard drafting team to continue its work on the associated standards without posting the SAR for another comment period.

- The drafting team added some clarifying words to improve the description of the proposed changes to FAC-012 and FAC-013
- The drafting team added several references to paragraphs in FERC Order 693 and FERC Order 890 that were omitted in the first posting of the SAR

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Anita Lee (G1) | Alberta Electric System Operator | | ✓ | | | | | | | | |
| 2. | Ken Goldsmith (G2) | ALT | ✓ | | | | ✓ | | | | | |
| 3. | E. Nick Henery | APPA | ✓ | | | | | | | | | |
| 4. | Matt Schull | APPA | ✓ | | | | | | | | | |
| 5. | Dave Rudolph (G2) | BEPC | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 6. | Brent Kingsford (G1) | California ISO | | ✓ | | | | | | | | |
| 7. | Greg Rowland | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 8. | Narinder K. Saini | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 9. | Narinder K. Saini | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 10. | Steve Myers (I) (G1) | ERCOT | | ✓ | | | | | | | | |
| 11. | Dave Folk | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 12. | Richard Kovacs | FirstEnergy Corp. EDPP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 13. | Phil Bowers | FirstEnergy Corp. EDPP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 14. | Joe Knight (G2) | Great River Energy | ✓ | | ✓ | | ✓ | | | | | |
| 15. | Roger Champagne (I) (G3) | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 16. | Danielle Beaulieu | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 17. | Ron Falsetti (I) (G1) | Independent Electricity System Operator (IESO) | | ✓ | | | | | | | | |
| 18. | Matthew F. Goldberg (I) (G1) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 19. | Kathleen Goodman (G3) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 20. | Brian Thumm | ITC Transco | ✓ | | | | | | | | | |
| 21. | Eric Ruskamp (G2) | LES | ✓ | | ✓ | | ✓ | ✓ | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 22. | Michelle Rheault | Manitoba Hydro EB | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 23. | Robert Coish (G2) | Manitoba Hydro EB | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 24. | Jerry Tank (G3) | MEAG | ✓ | | ✓ | | ✓ | | | | | |
| 25. | Dennis Kimm | MidAmerican Energy – Energy/Trading (MEC Trading) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 26. | Tom Mielnik (I) (G2) | MidAmerican Energy Co. (MEC) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 27. | Bill Phillips (G1) | Midwest ISO | | ✓ | | | | | | | | |
| 28. | Carol Gerou (G2) | Minnesota Power (MP) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 29. | Terry Bilke (G2) | MISO | | ✓ | | | | | | | | |
| 30. | Mike Brytowski (G2) | MRO | | | | | | | | | | ✓ |
| 31. | Jim Castle (G1) | New York ISO | | ✓ | | | | | | | | |
| 32. | Greg Campoli (G3) | New York ISO | | ✓ | | | | | | | | |
| 33. | Al Adamson (G3) | New York State Reliability Council | | | | | | | | | | ✓ |
| 34. | Guy V. Zito (G3) | NPCC | | | | | | | | | | ✓ |
| 35. | Todd Gosnell (G2) | OPPD | ✓ | | ✓ | | | ✓ | | | | |
| 36. | Alicia Daugherty (G1) | PJM | | ✓ | | | | | | | | |
| 37. | Philip Riley (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 38. | Mignon L. Clyburn (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 39. | G. O'Neal Hamilton (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 40. | John E. Howard (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 41. | Randy Mitchell (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 42. | C. Robert Moseley (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 43. | David A. Wright (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 44. | Charles Yeung (G1) | Southwest Power Pool | | ✓ | | | | | | | | |
| 45. | Jim Haigh (G2) | WAPA | ✓ | | | | | ✓ | | | | |
| 46. | Neal Balu (G2) | WPS | | | ✓ | | ✓ | ✓ | | | | |
| 47. | Pam Oreschnick (G2) | XEL | ✓ | | ✓ | | ✓ | ✓ | | | | |

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group

G1 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)
G3 – Midwest Reliability Organization (MRO)
G4 – IRC Standards Review Committee (IRC SRC)
G6 – Public Service Commission of South Carolina (PSC SC)

## Index to Questions, Comments, and Responses

1. NERC must address the directives in FERC Orders 890 and 693. Do you agree that this SAR is comprehensive enough to fully address the directives relative to ATC that are included in these Orders? If not, please explain in the comments area.

**Summary Consideration:** While most commenters indicated they do agree that the SAR is comprehensive enough to fully address the directives relative to ATC that are included in FERC Orders 890 and 693, there were some commenters who provided suggestions to further clarify the scope of additional work needed to fully comply with the directives and the SDT made the following changes to the SAR in support of those suggestions:

| Question #1 | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| APPA | | ☑ | The Supplemental SAR is incomplete and vague in directing the SDT as to its objective in providing new standards that will insure and/or improve the reliability of the BES. |
| **Response:** We have clarified the purpose statement to indicate that the changes being undertaken are to address the issues required in Orders 890 and 693 as described later in the SAR. | | | |
| IRC SRC | | ☑ | We agree that the SAR is comprehensive in addressing the FERC directives, and that changes to the MOD standards must be made to comply with the directives. However, this SAR is not comprehensive enough to provide the rationale and proposed scope and description on the restructuring of MOD-001, viz. the creation of MOD-028, MOD-029 and MOD-030, and more importantly, the retirement of FAC-012 and -013. And the revised SAR has not gone through a review and comment period before the newly created MOD-028, etc. are posted for comments.<br><br>The proposed restructuring of MOD-001, the creation of new standards and the retirement of FAC Standards are substantive changes to the original SAR. As such, the rationale and details need to be provided to the revised SAR and posted for comment. The industry needs to be given an opportunity to comment on the need and appropriateness of spliting the standards in this fashion, and the scope of each of the split standards.<br><br>The industry is now asked to comment both on the SAR and the revised and new MOD standards, which in our view makes commenting on the SAR as relates to the development of new MOD Standards almost irrelevant. |
| **Response:** The supplemental SAR is not intended to replace the SAR already approved to support modifications to MOD-001. The SAR for modifications to MOD-001 did envision having multiple processes for determining ATC or AFC – if all requirements are included in a single standard the standard would be extremely long and difficult to follow. The SDT has asked stakeholders for feedback on the acceptability of this division. A detailed explanation of this was included with the posted standard. | | | |

| Question #1 | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| Regarding the FAC-012 and -013 changes, we are not indicating that we are making this change; we are asking for the ability to make this change if the industry indicates that it should be made. We have asked the industry to comment on the retirement of FAC-012 and -013, and will take action based on those comments.<br><br>As far as the issue related to commenting on both the SAR and the MOD standards simultaneously, we recognize the concern expressed by the IRC. However, we are attempting to both address the needs of the industry and the need to comply with the FERC Order, and felt this was the best way to meet both the requirements of the NERC process and be responsive to the Commission. Note that the Reliability Standards Development Procedure does include the capability of posting a SAR and its associated standard(s) simultaneously. | | | |
| NPCC CP9 RSWG<br>HQT | ☑ | ☑ | The SAR will address all of the 77 directives from Orders 693 and 890 that are listed in Attachment 1. It is not clear if this list is comprehensive. Does the list include references have already been handled in the MOD standards currently under review, or does the list only included references yet to be addressed? |
| **Response:** The intent is for this list to be comprehensive. It includes both items that are currently being developed under the existing approved SARs, as well as items we expect to address under this supplemental SAR. | | | |
| IESO | ☑ | ☑ | The SAR proposes to address all of the 77 directives from Orders 693 and 890 that are listed in Attachment 1. However, it is not clear if this list is comprehensive. Does the list include references have already been handled in the MOD standards which are currently under review (MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1) or does the list only included those references which are not addressed by the above-mentioned standards under review currently? |
| **Response:** The intent is for this list to be comprehensive. It includes both items that are currently being developed under the existing SARs (in MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030), as well as items we expect to address under this supplemental SAR. | | | |
| FirstEnergy | ☑ | | While the summary of FERC Directives contained on pages SAR-6 and SAR-7 appears very complete, the summary uses a shorthad notation that it is somewhat cryptic and difficult to decypher. However, there appear to have been some ommissions as follows:<br>890-237 Consistent practices for calculating TTC/TFC<br>890-244 In short-term ATC calclulations all reserved but unused transfer capability shall be released as non-firm ATC<br>890-257 Develop standards for CBM determination, allocation and use<br>890-259 CBM only used to allow LSE to meet its generation reliaibility criteria<br>890-293 Approach for accounting for counter flows in ATC standards<br>890-301 ATC recalculation by TSP on a consistent time interval and in a manner tha closely reflects actual system topology<br>890-354 Unused transfer capability set aside for CBM made available for non-firm use and posted on OASIS<br>890-416 Posting of load data on LSE or BAA level of granularity rather than RTO/ISO total load |

| Question #1 | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| **Response:** We have included the references you suggested in the modified SAR. | | | |
| Duke Energy | ☑ | | |
| ITC | ☑ | | |
| Manitoba Hydro | ☑ | | |
| MEC | ☑ | | |
| MRO | ☑ | | |
| PSC SC | ☑ | | |

2. Please provide any other comments you have on the SAR.

**Summary Consideration:** There was a suggestion (see attached red-lined SAR from APPA) to provide more details to the scope of modifications proposed. Some of these modifications were adopted and are reflected in the revised SAR.

| Question #2 | |
|---|---|
| **Commenter** | **Comment** |
| APPA | The Following attach file contains modified versions of the Supplemental SAR sections that explains in detail the objective of the Supplemental SAR. These are recommended changes to SAR. See the Attached File with the recommended Changes. |
| **Response:** We have reviewed the suggestions and adopted the ones we believed were appropriate. Please see the comments on the attached file. | |
| FirstEnergy | Page SAR-2 paragraph FAC-012 and FAC-013 have misspellings "purposes o maintaining" should say "purpose of maintaining." |
| **Response:** We have fixed this error. | |
| NPCC CP9 RSWG HQT | Is it possible that the proposed SAR drafting team will revise the standards MOD-001, MOD-004, MOD-008, MOD-028, MOD-029 and MOD-030 that are currently under review? |
| **Response:** Yes, we will be modifying the MOD standards. This SAR is intended to supplement the existing work and team, not create a new team. | |
| IESO | Is it possible that the proposed SAR drafting team will revise the standards MOD-001, MOD-004, MOD-008, MOD-028, MOD-029 and MOD-030 that are currently under review? It might have been better that this SAR was addressed first and then the mentioned MOD standards if these were to be revised as a result of this supplemental SAR.<br><br>We do not agree with making the MOD-004 standard, a cluttered standard. This coupled with the need to make a distinction between the ATC calculation methods used and the descriptive procedure for resource adequacy assessment has made the new MOD-004 very convoluted, and the requirements difficult to follow and measure. If combining some standards of related objective is desired, a more manageable and appropriate alternative is to divide these 4 standards into two groups - one on the determining and verifying the calculation of CBM (Methodology, Assumptions, and Documentation) and the other on the use and reporting of use of CBM (Applicability and Reporting).<br><br>The roles of the Reliability Coordinator, Planning Coordinator, Transmission Owner, and the Transmission Service Provider must be clearly articulated in these standards as well as the new MOD standard that will come into effect as a result of FAC-012 and FAC-013. |
| **Response:** Yes, we will be modifying the MOD standards. This SAR is intended to supplement the existing work and team, not create a new team. | |

| **Question #2** | |
|---|---|
| **Commenter** | **Comment** |
| Regarding the MOD-004 changes, we will address this in the MOD-004 comments.<br><br>We will ensure the roles of the RC, PC, RO, TSP, and any other functional entities are clearly articulated. | |
| IRC SRC | From a process viewpoint, 3 new standards are created, and two standards are considered to be retired, without a SAR. This SAR that we are commenting on only provides the basis for making changes to address FERC directives, but does not list and provide the rationale for the new standards or the retirement of standards. This doesn't seem to be consistent with the reliability standards development procedure.<br><br>Similarly, there is no SAR or any mention in this SAR to combine MOD-004 to MOD-007. This is also a major change to the existing standards. A SAR to provide the rationale for the change, and the proposed scope of the consolidated standard need to be provided for industry comment, with sufficient time before any standard drafting work is done and the revised standards posted. |
| **Response:**<br>This supplemental SAR has been proposed to obtain stakeholder support on the expanded scope of work associated with full compliance with FERC Order 693 and FERC Order 890 relative to ATC, TTC, CBM, TRM and ETC<br>A SAR sets the scope of the technical content of the work, but leaves the structure of the actual standards to the Drafting Team's discretion. We currently have a SAR that allows us to address CBM and making changes to MOD-004, MOD -005, MOD -006, and MOD -008 (Feb 15 2006, "Revision to Standards MOD-004, MOD-005, MOD-006, MOD-008, and MOD-009"). We also have a SAR that allows us to address ATC and make changes to MOD-001 (Feb 15, 2005 "Revision to Existing Standard MOD-001-0"). The MOD-001 SAR does not preclude the Drafting Team from creating new standards. This Supplemental SAR is intended to address changes to MOD-002, MOD-003, MOD-007, FAC-012, and FAC-013 explicitly and to expand the scope of work done on MOD-001, MOD-004, MOD-005, MOD-006, MOD-008 and MOD-009 to fully address the directives in FERC Orders 693 and 890. | |
| ITC | This SAR appears to be necessary to inform FERC of potential inconsistencies in the propose standards that might be caused by a small number of the FERC orders. TTC for AFC/ATC does not belong in FAC-012 for example, even though FERC directed this. It's based on a misunderstanding of the original intent of FAC-012. As such, we support any work to clarify the meaning and intent of standards that are needed to meet FERC orders. |
| **Response:** We agree. | |
| MEC | I have no comment except to commend the Standards Drafting Team on doing a good job at developing the supplemental SAR and the revised standards to incorporate the FERC Orders. While I have comments on them, these revised standards as well as the supplemental SAR gets the NERC well on the way to responding to the FERC orders. |
| **Response:** Thank you. | |
| MRO | The MRO has no comment except to commend the Standards Drafting Team on doing a good job at developing the |

| Question #2 | |
|---|---|
| **Commenter** | **Comment** |
| | supplemental SAR and the revised standards to incorporate the FERC Orders. While the MRO has comments on them, these revised standards as well as the supplemental SAR gets the NERC well on the way to responding to the FERC orders. |
| **Response:** Thank you. | |

**Consideration of Comments on ATC Supplemental SAR**
**Attachment 1**

3. Attachment to the Supplemental SAR Comments from APPA

| | |
|---|---|
| Title of Proposed Standard | Revisions to existing Standards MOD-001 through MOD-009; FAC-012 through FAC-013. (This SAR is intended to supplement the two already approved SARs for "Revision to Existing Standard MOD-001" dated 2/15/2006 and "Revision to Standards MOD-004, MOD-005, MOD-006, MOD-008, MOD-009" ) |
| Request Date | May 23, 2007 |

| SAR Requester Information | SAR Type (***Check a box for each one that applies.***) | |
|---|---|---|
| Name The following members of the ATCT Drafting Team: | ☐<br>☐ | New Standard |
| Primary Contact | ☒ | Revision to existing Standard |
| Telephone<br>Fax | ☒<br>☐ | Withdrawal of existing Standard (possible) |
| E-mail | ☐<br>☐ | Urgent Action |

**Purpose**

This SAR is intended to supplement the SAR for "Revision to Existing Standard MOD-001" dated 2/15/2006, in response to FERC Orders 890 and 693. In evaluating the Orders, it has been discovered that additional modifications will be required to ensure clarity and consistency. Specifically, the following Standards may be modified, transferred to NAESB, or retired:

FAC-012 Transfer Capability Methodology
FAC-013 Establish and Communicate Transfer Capabilities
MOD-002 Review of TTC and ATC Calculations and Results
MOD-003 Procedure for Input on TTC and ATC Methodologies and Values
MOD-007 Documentation of the Use of CBM

**Industry Need** The FERC has directed NERC to provide these changes and clarifications in support of Preventing Undue Discrimination and Preference in Transmission Service, as well in support of Mandatory Reliability Standards for the Bulk Power System. NERC and the Industry will provide these changes and clarifications in support of Consistent Modeling Methods and Principles for Simulating Power Transfers and Determination of Transfer Capabilities, Timely and Accurate Communication of the Values of the TTC/TFC and the Assumptions Used to Calculate the TTC/TFC, and eliminating a fill-in-the-blank Standards.

NERC, as the ERO, is required to comply with all FERC directives.

**Drafting Team's response to proposed addition:** The industry need explains 'why' the SAR has been proposed but is not intended to identify the scope of proposed changes – the scope is addressed in the Brief Description and Detailed Description.

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**Brief Description** As directed by the FERC, the drafting team is developing proposed requirements to bring greater consistency and transparency to the calculation of TTC/TFC, ATC/AFC, ETC, CBM, and TRM. The modifications include elimination of the 'fill-in-the-blank' requirements. This possibility was identified in the original SAR; this supplemental SAR is requesting explicit ability to take action on these other standards as a part of the entire standards effort. This will be accomplished by the expansion of the exiting MOD-001 through 009 Standard Drafting Team. The expanded MOD-001 through 009 Standard Drafting Team will be comprised of personnel experienced and qualified in the calculation of the TTC/TFC for the planning and operating horizons and communicating those values and assumptions in a manner that will support the planning and operations of the BES and support efforts to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers.

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**Drafting Team's response to proposed addition:** The Standards Committee has control over appointments to drafting teams and it is not appropriate to add language in the SAR that controls the Standards Committee's actions. The intent of the Brief Description is to provide an overview of 'what' is proposed, not 'how' the team will achieve its proposed modifications.

**Detailed Description**
Actions of the drafting team may include:

FAC-012 Transfer Capability Methodology

Modification of FAC-012 or retirement of FAC-012 and movement to a new MOD standard. These standards are not related to Facility Design, Construction, and Maintenance. Rather, they are about the mathematical modeling used to analyze the bulk electric system for the purposes of maintaining reliable planning and operation of the BES and supporting efforts to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers. However, all of the FAC Standards series are relate and the modeling in Standard FAC -012 is directly related to FAC 001 through 011.

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Prepare for approval by the Industry, NERC BOT, and FERC a detailed standard that will provide the necessary requirements for the industry to develop Total Transfer Capabilities or Total Flowgate Capabilities utilizing methods that will meet the following requirements:

- Eliminate the "fill-in-blank" format of FAC-012-1
- The Standard will be written in a detailed format that incorporates the principles of calculating Total Transfer Capabilities or Total Flowgate Capabilities contained in "A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems;" dated 1995; Titled Transmission Transfer Capability; published by the North American Electric Reliability Council.
- The Standard will be written to include detailed requirements for eliminating discontinuity at the seams between Regions that utilize different methods of calculating Total Transfer Capability or Total Flowgate Capabilities.
- The Standard will retire the glossary term Transfer Capability and modify, if necessary, the glossary term Total Transfer Capability to be consistent with the principles contained in the this Standard.
- The Standard will insure that the Applicable Reliability Functions calculate the values of the Total Transfer Capabilities or Total Flowgate Capabilities for planning and operating horizons in a timely manner that will support the planning and operations of the BES and support

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marketing effort to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers.

FAC-013 Establish and Communicate Transfer Capabilities
Modification of FAC-013 or retirement of FAC-013 and incorporation into a new MOD standard. These standards are not related to Facility Design, Construction, and Maintenance. Rather, they are about the mathematical modeling used to analyze the bulk electric system for the purposes of maintaining reliable planning and operation of the BES and supporting efforts to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers.

Prepare for approval by the Industry, NERC BOT, and FERC a detailed standard that will provide the necessary requirements for the industry to timely communicate the values of the Total Transfer Capability or Total Flowgate Capability calculated in accordance with the requirements of FAC-012; and to communicate, when required by other Standards, the assumptions used to calculate the values of the Total Transfer Capability or Total Flowgate Capability to support reliable operations and the marketing requirements of Available Transfer Capability.
The assumptions used to determine the Total Transfer Capability or Total Flow Capability communicated to the industry shall, without violating confidentially or security requirements, include, but not be limited to:

- Existing Transmission Commitments Used for Planned Scheduled Energy Transfers
- Projected Loads
- Planned Generator Unit Commitments
- Planned System Configuration of the Interconnected System
- System Contingencies Assumed During the Studies
- Impacts of Neighboring Systems
- Impacts on Neighboring Systems

MOD-002 Review of TTC and ATC Calculations and Results
Incorporation into MOD-001 and retirement. It is believed that much of this is related to the measurement and compliance aspects of Available Transfer Capability, and will be handled as such.
MOD-003 Procedure for Input on TTC and ATC Methodologies and Values
Transfer to NAESB and retirement. It is believed that this standard is more focused on business practices.
MOD-007 Documentation of the Use of CBM
Incorporation into MOD-004 and retirement. It is believed that much of this is related to the measurement and compliance aspects of CBM, and will be handled as such.

The drafting team will address all of the directives in FERC Order 693 and FERC Order 890 listed in Attachment 1.

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**Drafting Team's response to proposed additions:** The drafting team adopted the proposed additions that provide clarification but determined that the proposed modifications highlighted in yellow either provided information that is not needed for the revisions proposed under this SAR or propose additional requirements beyond those associated with compliance with the FERC Orders.

**Reliability Functions**

| The Standard will Apply to the Following Functions *(Check box for each one that applies.)* | | |
|---|---|---|
| ☒ | Reliability Coordinator | **Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.** |
| ☒ | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time. |
| ☐ | Interchange Coordinator | Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas. |
| ☒ | Planning Coordinator | Assesses the longer-term reliability of its Planning Coordinator Area. |
| ☐ | Resource Planner | Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area. |
| ☒ | Transmission Planner | Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area. |
| ☒ | Transmission Service Provider | Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff). |
| ☒ | Transmission Owner | Owns and maintains transmission facilities. |
| ☒ | Transmission Operator | Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area. |
| ☐ | Distribution Provider | Delivers electrical energy to the End-use customer. |
| ☒ | Generator Owner | Owns and maintains generation facilities. |
| ☐ | Generator Operator | Operates generation unit(s) to provide real and reactive power. |
| ☒ | Purchasing-Selling Entity | Purchases or sells energy, capacity, and necessary reliability-related services as required. |
| ☐ | Market Operator | Interface point for reliability functions with commercial functions. |
| ☒ | Load-Serving Entity | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view. |

**Reliability and Market Interface Principles**

| Applicable Reliability Principles ***(Check box for all that apply.)*** | |
|---|---|
| ☒ | 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☒ | 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☐ | 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented. |
| ☐ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems. |
| ☒ | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis. |
| ☐ | 8. Bulk power systems shall be protected from malicious physical or cyber attacks. |

| Does the proposed Standard comply with all of the following Market Interface Principles? ***(Select 'yes' or 'no' from the drop-down box.)*** |
|---|
| A reliability standard shall not give any market participant an unfair competitive advantage. Yes |
| A reliability standard shall neither mandate nor prohibit any specific market structure. Yes |
| A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes |
| A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

**Related Standards**

| Standard No. | Explanation |
|---|---|
| None | None |
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**Related SARs**

| SAR ID | Explanation |
|---|---|
| None | None |
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**Regional Variances**

| Region | Explanation |
|---|---|
| ERCOT | None |
| FRCC | None |
| MRO | None |
| NPCC | None |
| SERC | None |
| RFC | None |
| SPP | None |
| WECC | None |

| **Directives from Order 693 and 890 related to ATC Standards** |
|---|
| 693-782 Directs the ERO to modify FAC-012 to calculate transfer capability for ATC calculations and eliminate fill-in-the-blank format. |
| 693-783 Recognized that the change for FAC-012 is on the schedule set in Order 890 |
| 693-1050 TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. |
| 693-1051 The Commission directs the ERO, through the Reliability Standards development process, to modify FAC-012-1 and any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the pro forma OATT, |
| 693-1057 Develop non-fill-in-the-blank Standard |
| 693-1057 Define information to be shared between TSPs for ATC calculations |
| 693-1057 Planning Assumptions and ATC Assumptions should be the same |
| 890-292 Planning Assumptions and ATC Assumptions should be the same |
| 890-292 Load levels the same plan/ops vs. ATC |
| 890-292 Gen Dispatch the same plan/ops vs. ATC |
| 890-292 TX and Gen Facilities maintenance the same plan/ops vs. ATC |
| 890-292 Contingency outages the same plan/ops vs. ATC |
| 890-292 Topology the same plan/ops vs. ATC |
| 890-292 TX Reservations the same plan/ops vs. ATC |
| 890-292 Assumptions re: additions and retirements the same plan/ops vs. ATC |
| 890-292 Counterlfows the same plan/ops vs. ATC |
| 890-295 Load level modeling methodology the same |
| 890-296 Dispatch should include all DNRs and committed resources as expected to run, and uncommitted resources deliverable within CA, economically dispatched to meet balancing needs |
| 890-297 How to model POR to POD without source/sink |
| 890-297 How to model existing reservations |
| 693-1057 ATC should be updated on a consistent schedule |
| 693-1057 ATC/TTC Assumptions and Contingencies must be made available |
| 693-1057 Put TTC in FAC section |
| 693-1057 Identify applicable entities |
| 693-1105 CBM must be 0 in non-firm ATC |
| 890-262 CBM =0 in Non-Firm Calc |
| 890-273 TRM <> =0 in Non-Firm Calc |
| 890-211 Standard AFC->ATC Calculation |

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890-212 Firm ATC uses only Firm Commitments
890-212 Non-Firm ATC uses firm and non-firm commitments, postbacks or redirected services, unscheduled service, and counterflows
890-237 Address differencess between Pro-Forma TTC and Native Load/Reliability Assessment TTC
890-243 Standard calc of native load use - include in MOD-001
890-244 ETC = Native load (including Network)
890-244 ETC = Grandfathered
890-244 ETC = Appropriate PTP
890-244 ETC = Long-term Rollover rights
890-244 Define any additional ETC components
890-245 Reservations with Same POR whose SUM would exceed gen nameplate must be addressed
890-310 Mandatory Data Exchange for ATC
890-310 DEX Load
890-310 DEX TX Plan and Contingency outages
890-310 DEX Gen Plan and Contingency outages
890-310 DEX Base dispatch
890-310 DEX existing reservations incl counterflows
890-310 DEX ATC recalc frequencies and times
890-310 DEX Source sink modeling identification
890=389 Unscheduled Reservation released on non-firm and posted on OASIS

**Drafting Team's response to suggested additions:**

- Order 693, paragraph 782 does not include the referenced language.
- Order 693, paragraph 783 does not include a directive.
- Order 693, paragraph 1050 - the notation provided was added to the revised SAR
- Order 693, paragraph 1051 – the notation provided was added to the revised SAR

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# Standard Authorization Request Form

| | |
|---|---|
| Title of Proposed Standard | Revisions to existing Standards MOD-001 through MOD-009; FAC-012 through FAC-013. (This SAR is intended to supplement the two already approved SARs for "Revision to Existing Standard MOD-001" dated 2/15/2006 and "Revision to Standards MOD-004, MOD-005, MOD-006, MOD-008, MOD-009" ) |
| Request Date | May 23, 2007 |
| Revised Date | July 31, 2007 |

| **SAR Requester Information** | | **SAR Type** (*Check a box for each one that applies.*) |
|---|---|---|
| Name The following members of the ATCT Drafting Team:<br>Chuck Falls<br>Ross Kovacs<br>Laura Lee<br>Cheryl Mendrala<br>Nate Schweighart | ☐ | New Standard |
| Primary Contact Laura Lee | ☒ | Revision to existing Standard |
| Telephone (704) 382-3625<br>Fax | ☒ | Withdrawal of existing Standard (possible) |
| E-mail | ☐ | Urgent Action |

**Purpose**

This SAR is intended to supplement the SAR for "Revision to Existing Standard MOD-001" dated 2/15/2006, in response to FERC Orders 890 and 693. In evaluating the Orders, it has been discovered that additional modifications will be required to ensure clarity and consistency. Specifically, the following Standards may be modified per the items described herein, transferred to NAESB, or retired:

FAC-012 Transfer Capability Methodology
FAC-013 Establish and Communicate Transfer Capabilities
MOD-002 Review of TTC and ATC Calculations and Results
MOD-003 Procedure for Input on TTC and ATC Methodologies and Values
MOD-007 Documentation of the Use of CBM

**Industry Need** The FERC has directed NERC to provide these changes and clarifications in support of Preventing Undue Discrimination and Preference in Transmission Service, as well in support of Mandatory Reliability Standards for the Bulk Power System.

NERC, as the ERO is required to comply with all FERC directives.

**Brief Description** As directed by the FERC, the drafting team is developing proposed requirements to bring greater consistency and transparency to the calculation of TTC/TFC, ATC/AFC, ETC, CBM, and TRM. The modifications include elimination of the 'fill-in-the-blank' requirements. This possibility was identified in the original SAR; this supplemental SAR is requesting explicit ability to take action on these other standards as a part of the entire standards effort.

**Detailed Description**

Actions of the drafting team may include:

FAC-012 Transfer Capability Methodology

Modification of FAC-012 or retirement of FAC-012 and movement to a new MOD standard. These standards are not related to Facility Design, Construction, and Maintenance. Rather, they are about the mathematical modeling used to analyze the Bulk Electric System (BES) for the purposes of maintaining reliable planning and operation of the BES and supporting efforts to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers..

FAC-013 Establish and Communicate Transfer Capabilities

Modification of FAC-013 or retirement of FAC-013 and incorporation into a new MOD standard. These standards are not related to Facility Design, Construction, and Maintenance. Rather, they are about the mathematical modeling used to analyze the bulk electric system for the purposes of maintaining reliable planning and operation of the BES and supporting efforts to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers.

MOD-002 Review of TTC and ATC Calculations and Results

Incorporation into MOD-001 and retirement. It is believed that much of this is related to the measurement and compliance aspects of Available Transfer Capability, and will be handled as such.

MOD-003 Procedure for Input on TTC and ATC Methodologies and Values

Transfer to NAESB and retirement. It is believed that this standard is more focused on business practices.

MOD-007 Documentation of the Use of CBM

Incorporation into MOD-004 and retirement. It is believed that much of this is related to the measurement and compliance aspects of CBM, and will be handled as such.

The drafting team will address all of the directives in FERC Order 693 and FERC Order 890 listed in Attachment 1.

***Reliability Functions***

| **The Standard will Apply to the Following Functions** *(Check box for each one that applies.)* | | |
|---|---|---|
| ☒ | Reliability Coordinator | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view. |
| ☒ | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time. |
| ☐ | Interchange Coordinator | Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas. |
| ☒ | Planning Coordinator | Assesses the longer-term reliability of its Planning Coordinator Area. |
| ☐ | Resource Planner | Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area. |
| ☒ | Transmission Planner | Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area. |
| ☒ | Transmission Service Provider | Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff). |
| ☒ | Transmission Owner | Owns and maintains transmission facilities. |
| ☒ | Transmission Operator | Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area. |
| ☐ | Distribution Provider | Delivers electrical energy to the End-use customer. |
| ☒ | Generator Owner | Owns and maintains generation facilities. |
| ☐ | Generator Operator | Operates generation unit(s) to provide real and reactive power. |
| ☒ | Purchasing-Selling Entity | Purchases or sells energy, capacity, and necessary reliability-related services as required. |
| ☐ | Market Operator | Interface point for reliability functions with commercial functions. |
| ☒ | Load-Serving Entity | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view. |

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***Reliability and Market Interface Principles***

| **Applicable Reliability Principles** *(Check box for all that apply.)* | |
|---|---|
| ☒ | 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☒ | 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☐ | 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented. |
| ☐ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems. |
| ☒ | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis. |
| ☐ | 8. Bulk power systems shall be protected from malicious physical or cyber attacks. |

| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box.)* |
|---|
| 1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

***Related Standards***

| **Standard No.** | **Explanation** |
|---|---|
| None | None |
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***Related SARs***

| **SAR ID** | **Explanation** |
|---|---|
| None | None |
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***Regional Variances***

| **Region** | **Explanation** |
|---|---|
| ERCOT | None |
| FRCC | None |
| MRO | None |
| NPCC | None |
| SERC | None |
| RFC | None |
| SPP | None |
| WECC | None |

**Directives from Order 693 and 890 related to ATC Standards (including TTC)**

693-1050 TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0.
693-1051 Modify FAC-012-1 and any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the pro forma OATT
693-1057 Develop non-fill-in-the-blank Standard
693-1057 Define information to be shared between TSPs for ATC calculations
693-1057 Planning Assumptions and ATC Assumptions should be the same
890-292 Planning Assumptions and ATC Assumptions should be the same
890-292 Load levels the same plan/ops vs. ATC
890-292 Gen Dispatch the same plan/ops vs. ATC
890-292 TX and Gen Facilities maintenance the same plan/ops vs. ATC
890-292 Contingency outages the same plan/ops vs. ATC
890-292 Topology the same plan/ops vs. ATC
890-292 TX Reservations the same plan/ops vs. ATC
890-292 Assumptions re: additions and retirements the same plan/ops vs. ATC
890-292 Counterlfows the same plan/ops vs. ATC
890-295 Load level modeling methodology the same
890-296 Dispatch should include all DNRs and committed resources as expected to run, and uncommitted resources deliverable within CA, economically dispatched to meet balancing needs
890-297 How to model POR to POD without source/sink
890-297 How to model existing reservations
693-782 Criteria used to calculate transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system.
693-1057 ATC should be updated on a consistent schedule
693-1057 ATC/TTC Assumptions and Contingencies must be made available
693-1057 Put TTC in FAC section
693-1057 Identify applicable entities
693-1105 CBM must be 0 in non-firm ATC
890-262 CBM =0 in Non-Firm Calc
890-273 TRM <> =0 in Non-Firm Calc
890-211 Standard AFC->ATC Calculation
890-212 Firm ATC uses only Firm Commitments
890-212 Non-Firm ATC uses firm and non-firm commitments, postbacks or redirected services, unscheduled service, and counterflows
890-237 Develop consistent practices for calculating TTC/TFC
890-237 Address differences between Pro-Forma TTC and Native Load/Reliability Assessment TTC
890-243 Standard calc of native load use - include in MOD-001
890-244 In the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC.
890-244 ETC = Native load (including Network)
890-244 ETC = Grandfathered
890-244 ETC = Appropriate PTP
890-244 ETC = Long-term Rollover rights
890-244 Define any additional ETC components
890-245 Reservations with Same POR whose SUM would exceed gen nameplate must be addressed
890-293 Develop an approach for accounting for counterflows, in the relevant ATC standards and business practices.
890-301 ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system,
890-310 Mandatory Data Exchange for ATC

890-310 DEX Load
890-310 DEX TX Plan and Contingency outages
890-310 DEX Gen Plan and Contingency outages
890-310 DEX Base dispatch
890-310 DEX existing reservations incl counterflows
890-310 DEX ATC recalc frequencies and times
890-310 DEX Source sink modeling identification
890-389 Unscheduled Reservation released on non-firm and posted on OASIS
890-237 Develop consistent practices for calculating TTC/TFC
890-244 In the short-term ATC calclulation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC.
890-293 Develop an approach for accounting for counterflows, in the relevant ATC standards and business practices.
890-301 ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system,
890-416 Direct ISOs and RTOs to post load data for the entire ISO/RTO footprint and for each LSE or control area footprint within the ISO/RTO.

| Directives from Order 693 and 890 related to CBM Standard |
|---|
| 693-1082 CBM set aside at verified request of LSE |
| 693-1082 Require disclosure of CBM studies |
| 693-1082 Define flowgate/path allocation process for CBM |
| 693-1082 No double counting |
| 693-1082 Add LSE, BA as applicable entity where necessary |
| 693-1105 CBM Must be used only for generation deficiencies |
| 693-1105 Generation Deficiency must be states as an EEA level |
| 890-257 Develop clear standards for how the CBM value shall be determined, allocated across transmission paths, and used. |
| 890-259 CBM shall only used to allow LSE to meet its generation reliability criteria |
| 890-260 Define flowgate/path allocation process for CBM |
| 890-262 CBM Must be used only for generation deficiencies |
| 890-354 Commission requires transmission providers to make any transfer capability set aside for CBM but unused for such purpose available on a non-firm basis and to post this availability on OASIS. |
| 890-358 yearly CBM studies |
| 693-1081 What to do if CBM exceeds ATC? |
| **Directives from Order 693 and 890 related to TRM Standard** |
| 693-1122 Define flowgate/path allocation process for TRM |
| 693-1126 Explicit definition of what goes into TRM |
| 693-1122 TRM = Load Forecast and Load Distribution Error |
| 693-1122 TRM = Variation in facility loading |
| 693-1122 TRM = uncertainty in transmission topology |
| 693-1122 TRM = loop flow |
| 693-1122 TRM = variations in dispatch |
| 693-1122 TRM = ARS |
| 693-1122 Define any additional uses |
| 890-273 Explicit definition of what goes into TRM |
| 890-273 TRM = Load Forecast and Load Distribution Error |
| 890-273 TRM = Variation in facility loading |
| 890-273 TRM = uncertainty in tx topology |
| 890-273 TRM = loop flow |
| 890-273 TRM = variations in dispatch |
| 890-273 TRM = ARS |
| 890-273 Define any additional uses |
| 693-1082 No double counting |
| 890-273 No double counting |
| 693-1126 Max TRM Calc |
| 890-275 Max TRM Calc |
| 693-1126 Standard on How TRM to be calculated |
| 693-1126 Add PC, RE to applicable entities |

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# Standard Authorization Request Form

| | |
|---|---|
| Title of Proposed Standard | Revisions to existing Standards MOD-001 through MOD-009; FAC-012 through FAC-013. (This SAR is intended to supplement the two already approved SARs for "Revision to Existing Standard MOD-001" dated 2/15/2006 and "Revision to Standards MOD-004, MOD-005, MOD-006, MOD-008, MOD-009" ) |
| Request Date | May 23, 2007 |
| Revised Date | July 31, 2007 |

| **SAR Requester Information** | **SAR Type** (*Check a box for each one that applies.*) | |
|---|---|---|
| Name The following members of the ATCT Drafting Team:<br>Chuck Falls<br>Ross Kovacs<br>Laura Lee<br>Cheryl Mendrala<br>Nate Schweighart | ☐ | New Standard |
| Primary Contact Laura Lee | ☒ | Revision to existing Standard |
| Telephone (704) 382-3625<br>Fax | ☒ | Withdrawal of existing Standard (possible) |
| E-mail | ☐ | Urgent Action |

**Purpose**

This SAR is intended to supplement the SAR for "Revision to Existing Standard MOD-001" dated 2/15/2006, in response to FERC Orders 890 and 693. In evaluating the Orders, it has been discovered that additional modifications will be required to ensure clarity and consistency. Specifically, the following Standards may be modified per the items described herein, transferred to NAESB, or retired:

FAC-012 Transfer Capability Methodology
FAC-013 Establish and Communicate Transfer Capabilities
MOD-002 Review of TTC and ATC Calculations and Results
MOD-003 Procedure for Input on TTC and ATC Methodologies and Values
MOD-007 Documentation of the Use of CBM

**Industry Need** The FERC has directed NERC to provide these changes and clarifications in support of Preventing Undue Discrimination and Preference in Transmission Service, as well in support of Mandatory Reliability Standards for the Bulk Power System.

NERC, as the ERO is required to comply with all FERC directives.

**Brief Description** As directed by the FERC, the drafting team is developing proposed requirements to bring greater consistency and transparency to the calculation of TTC/TFC, ATC/AFC, ETC, CBM, and TRM. The modifications include elimination of the 'fill-in-the-blank' requirements. This possibility was identified in the original SAR; this supplemental SAR is requesting explicit ability to take action on these other standards as a part of the entire standards effort.

**Detailed Description**

Actions of the drafting team may include:

FAC-012 Transfer Capability Methodology

Modification of FAC-012 or retirement of FAC-012 and movement to a new MOD standard. These standards are not related to Facility Design, Construction, and Maintenance. Rather, they are about the mathematical modeling used to analyze the Bulk Electric System (BES) for the purposes of maintaining reliable planning and operation of the BES and supporting efforts to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers.

FAC-013 Establish and Communicate Transfer Capabilities

Modification of FAC-013 or retirement of FAC-013 and incorporation into a new MOD standard. These standards are not related to Facility Design, Construction, and Maintenance. Rather, they are about the mathematical modeling used to analyze the bulk electric system for the purposes of maintaining reliable planning and operation of the BES and supporting efforts to make Available Transfer Capability methods and results transparent to the industry's Transmission Customers.

MOD-002 Review of TTC and ATC Calculations and Results

Incorporation into MOD-001 and retirement. It is believed that much of this is related to the measurement and compliance aspects of Available Transfer Capability, and will be handled as such.

MOD-003 Procedure for Input on TTC and ATC Methodologies and Values

Transfer to NAESB and retirement. It is believed that this standard is more focused on business practices.

MOD-007 Documentation of the Use of CBM

Incorporation into MOD-004 and retirement. It is believed that much of this

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is related to the measurement and compliance aspects of CBM, and will be handled as such.

The drafting team will address all of the directives in FERC Order 693 and FERC Order 890 listed in Attachment 1.

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***Reliability Functions***

| The Standard will Apply to the Following Functions *(Check box for each one that applies.)* | | |
|---|---|---|
| ☒ | Reliability Coordinator | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view. |
| ☒ | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time. |
| ☐ | Interchange Coordinator | Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas. |
| ☒ | Planning Coordinator | Assesses the longer-term reliability of its Planning Coordinator Area. |
| ☐ | Resource Planner | Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area. |
| ☒ | Transmission Planner | Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area. |
| ☒ | Transmission Service Provider | Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff). |
| ☒ | Transmission Owner | Owns and maintains transmission facilities. |
| ☒ | Transmission Operator | Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area. |
| ☐ | Distribution Provider | Delivers electrical energy to the End-use customer. |
| ☒ | Generator Owner | Owns and maintains generation facilities. |
| ☐ | Generator Operator | Operates generation unit(s) to provide real and reactive power. |
| ☒ | Purchasing-Selling Entity | Purchases or sells energy, capacity, and necessary reliability-related services as required. |
| ☐ | Market Operator | Interface point for reliability functions with commercial functions. |
| ☒ | Load-Serving Entity | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view. |

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***Reliability and Market Interface Principles***

| **Applicable Reliability Principles** *(Check box for all that apply.)* | |
|---|---|
| ☒ | 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☒ | 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☐ | 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented. |
| ☐ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems. |
| ☒ | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis. |
| ☐ | 8. Bulk power systems shall be protected from malicious physical or cyber attacks. |

| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box.)* |
|---|
| 1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

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***Related Standards***

| **Standard No.** | **Explanation** |
|---|---|
| None | None |
| | |
| | |
| | |

***Related SARs***

| **SAR ID** | **Explanation** |
|---|---|
| None | None |
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***Regional Variances***

| **Region** | **Explanation** |
|---|---|
| ERCOT | None |
| FRCC | None |
| MRO | None |
| NPCC | None |
| SERC | None |
| RFC | None |
| SPP | None |
| WECC | None |

**Directives from Order 693 and 890 related to ATC Standards (including TTC)**

693-1050 TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0.
693-1051 Modify FAC-012-1 and any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the pro forma OATT
693-1057 Develop non-fill-in-the-blank Standard
693-1057 Define information to be shared between TSPs for ATC calculations
693-1057 Planning Assumptions and ATC Assumptions should be the same
890-292 Planning Assumptions and ATC Assumptions should be the same
890-292 Load levels the same plan/ops vs. ATC
890-292 Gen Dispatch the same plan/ops vs. ATC
890-292 TX and Gen Facilities maintenance the same plan/ops vs. ATC
890-292 Contingency outages the same plan/ops vs. ATC
890-292 Topology the same plan/ops vs. ATC
890-292 TX Reservations the same plan/ops vs. ATC
890-292 Assumptions re: additions and retirements the same plan/ops vs. ATC
890-292 Counterlfows the same plan/ops vs. ATC
890-295 Load level modeling methodology the same
890-296 Dispatch should include all DNRs and committed resources as expected to run, and uncommitted resources deliverable within CA, economically dispatched to meet balancing needs
890-297 How to model POR to POD without source/sink
890-297 How to model existing reservations
693-782 Criteria used to calculate transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system.
693-1057 ATC should be updated on a consistent schedule
693-1057 ATC/TTC Assumptions and Contingencies must be made available
693-1057 Put TTC in FAC section
693-1057 Identify applicable entities
693-1105 CBM must be 0 in non-firm ATC
890-262 CBM =0 in Non-Firm Calc
890-273 TRM <> =0 in Non-Firm Calc
890-211 Standard AFC->ATC Calculation
890-212 Firm ATC uses only Firm Commitments
890-212 Non-Firm ATC uses firm and non-firm commitments, postbacks or redirected services, unscheduled service, and counterflows
890-237 Develop consistent practices for calculating TTC/TFC
890-237 Address differences between Pro-Forma TTC and Native Load/Reliability Assessment TTC
890-243 Standard calc of native load use - include in MOD-001
890-244 In the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC.
890-244 ETC = Native load (including Network)
890-244 ETC = Grandfathered
890-244 ETC = Appropriate PTP
890-244 ETC = Long-term Rollover rights
890-244 Define any additional ETC components
890-245 Reservations with Same POR whose SUM would exceed gen nameplate must be addressed
890-293 Develop an approach for accounting for counterflows, in the relevant ATC standards and business practices.
890-301 ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system,
890-310 Mandatory Data Exchange for ATC

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890-310 DEX Load
890-310 DEX TX Plan and Contingency outages
890-310 DEX Gen Plan and Contingency outages
890-310 DEX Base dispatch
890-310 DEX existing reservations incl counterflows
890-310 DEX ATC recalc frequencies and times
890-310 DEX Source sink modeling identification
890-389 Unscheduled Reservation released on non-firm and posted on OASIS
890-237 Develop consistent practices for calculating TTC/TFC
890-244 In the short-term ATC calclulation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC.
890-293 Develop an approach for accounting for counterflows, in the relevant ATC standards and business practices.
890-301 ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system,
890-416 Direct ISOs and RTOs to post load data for the entire ISO/RTO footprint and for each LSE or control area footprint within the ISO/RTO.

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| Directives from Order 693 and 890 related to CBM Standard |
|---|
| 693-1082 CBM set aside at verified request of LSE |
| 693-1082 Require disclosure of CBM studies |
| 693-1082 Define flowgate/path allocation process for CBM |
| 693-1082 No double counting |
| 693-1082 Add LSE, BA as applicable entity where necessary |
| 693-1105 CBM Must be used only for generation deficiencies |
| 693-1105 Generation Deficiency must be states as an EEA level |
| 890-257 Develop clear standards for how the CBM value shall be determined, allocated across transmission paths, and used. |
| 890-259 CBM shall only used to allow LSE to meet its generation reliability criteria |
| 890-260 Define flowgate/path allocation process for CBM |
| 890-262 CBM Must be used only for generation deficiencies |
| 890-354 Commission requires transmission providers to make any transfer capability set aside for CBM but unused for such purpose available on a non-firm basis and to post this availability on OASIS. |
| 890-358 yearly CBM studies |
| 693-1081 What to do if CBM exceeds ATC? |
| **Directives from Order 693 and 890 related to TRM Standard** |
| 693-1122 Define flowgate/path allocation process for TRM |
| 693-1126 Explicit definition of what goes into TRM |
| 693-1122 TRM = Load Forecast and Load Distribution Error |
| 693-1122 TRM = Variation in facility loading |
| 693-1122 TRM = uncertainty in transmission topology |
| 693-1122 TRM = loop flow |
| 693-1122 TRM = variations in dispatch |
| 693-1122 TRM = ARS |
| 693-1122 Define any additional uses |
| 890-273 Explicit definition of what goes into TRM |
| 890-273 TRM = Load Forecast and Load Distribution Error |
| 890-273 TRM = Variation in facility loading |
| 890-273 TRM = uncertainty in tx topology |
| 890-273 TRM = loop flow |
| 890-273 TRM = variations in dispatch |
| 890-273 TRM = ARS |
| 890-273 Define any additional uses |
| 693-1082 No double counting |
| 890-273 No double counting |
| 693-1126 Max TRM Calc |
| 890-275 Max TRM Calc |
| 693-1126 Standard on How TRM to be calculated |
| 693-1126 Add PC, RE to applicable entities |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a standard drafting team on March 17, 2006.

**Description of Current Draft:**

This is the first draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR with consideration of applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Respond to comments. | TBD |
| 2. Post revised standard for stakeholder comment. | TBD |
| 3. Respond to comments. | TBD |
| 4. Post for 30-day pre-ballot review. | TBD |
| 5. First ballot of standard. | TBD |
| 6. Respond to comments. | TBD |
| 7. Recirculation ballot. | TBD |
| 8. 30-day posting before board adoption. | TBD |
| 9. Board adoption. | TBD |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title:** **Flowgate Network Response Available Transfer Capability**

2. **Number:** MOD-030-1

3. **Purpose:** To promote the consistent and uniform application and documentation of Available Transfer Capability (ATC) calculations performed using the Flowgate Network Response method for reliable system operations.

4. **Applicability:**

   **4.1.** Each Planning Coordinator that uses the Flowgate Network Response method to calculate Available Transfer Capabilities for paths identified in an Available Transfer Capability Implementation Document.

   **4.2.** Each Reliability Coordinator that uses the Flowgate Network Response method to calculate Available Transfer Capabilities for paths identified in an Available Transfer Capability Implementation Document.

   **4.3.** Each Transmission Service Provider that uses the Flowgate Network Response method to calculate Available Transfer Capabilities for paths identified in an Available Transfer Capability Implementation Document.

5. **Proposed Effective Date:** To be determined.

## B. Requirements

**R1.** Each Planning Coordinator and Reliability Coordinator shall include, in its "Available Transfer Capability Implementation Document" for a specific Transmission Service Provider, the criteria used to identify sets of transmission Facilities as Flowgates that are to be considered by the Transmission Service Provider when analyzing requests for service. At a minimum, the criteria shall specify:

**R1.1.** How the methodology meets the planning criteria in TPL-001 and TPL-002, for the Contingencies in Table 1, Category B or the successor criteria.

**R1.2.** How the methodology identifies transmission Facilities that are expected by the AFC calculator to cause congestion on the transmission system.

**R1.3.** The treatment of transmission Facilities that have historically been constrained.

**R2.** Each Planning Coordinator and Reliability Coordinator associated with a Transmission Service Provider shall, at a minimum, create, modify, or delete Flowgates as necessary at the beginning of every calendar quarter, based on the criteria specified in R1.

**R3.** The Transmission Service Provider shall ensure the definitions of all Flowgates specified by the Planning Coordinator and Reliability Coordinator are made publicly available, including the type of Flowgate (thermal, voltage, or stability).

**R4.** Each Transmission Owner and Transmission Planner shall provide its Transmission Service Provider with the current thermal limits for thermally limited Flowgates.

**R5.** The Transmission Service Provider shall use the current thermal limits provided by the Transmission Planner and Transmission Operator as the Total Flowgate Capability (TFC).

**R6.** Each Planning Coordinator and Reliability Coordinator shall provide its Transmission Service Provider with the current voltage and stability limits for voltage or stability limited Flowgates, respectively.

**R7.** The Transmission Service Provider shall use the voltage and stability limits provided by its Planning Coordinator and Reliability Coordinator as the TFC.

**R8.** Each Planning Coordinator and Reliability Coordinator associated with a Transmission Service Provider shall ensure that TFC for each of the specified Flowgates for that Transmission Service Provider is equal to the lesser of:

- The Thermal Rating of the Flowgate, or
- The voltage limit of power transferred across the Flowgate, if applicable, or
- The Stability Limit of power transferred across the Flowgate, if applicable.

**R9.** Each Planning Coordinator and Reliability Coordinator associated with a Transmission Service Provider shall ensure that TFC for all the specified Flowgates for that Transmission Service Provider are calculated for use within the Transfer Capability time horizons specified in MOD-001.

**R10.** Each Planning Coordinator and Reliability Coordinator shall make available to its Transmission Service Provider the results of the calculations of TFC for all the specified Flowgates of that Transmission Service Provider upon completion of the calculation.

**R11.** The Transmission Service Provider shall make publicly available the results of the calculations of TFC provided by the Planning Coordinator and Reliability Coordinator upon their being made available to the Transmission Service Provider.

**R12.** The Transmission Service Provider shall calculate Available Flowgate Capability (AFC) for the time horizons specified in MOD-001 R2 according to the ATC schedule specified in MOD-001 R5.

**R13.** The Transmission Service Provider shall calculate Firm AFC by reducing the TFC by the sum of the firm Existing Transmission Commitments (ETCs), the Capacity Benefit Margin (CBM), and the Transmission Reliability Margin (TRM) allocated to the Flowgate.

**R14.** The Transmission Service Provider shall determine the impact of firm ETCs based on the following inputs:

- The transmission capability utilized in serving Native Load commitments, to include Native Load growth, Load forecast error and losses not otherwise included in TRM or CBM.
- The impact of Firm Network Integration Transmission Service serving Load, to include Load forecast error and losses not otherwise included in TRM or CBM.
- The impact of grandfathered firm Transmission Service Agreements and bundled contracts for energy and transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or Safe Harbor Tariff accepted by FERC.

- The impact of Firm Point to Point Transmission Service,
- The impact of maintaining roll-over rights for Firm Transmission Service contracts, five years or longer in duration, granting Transmission Customers the right of first refusal to take or continue to take Transmission Service from a Transmission Owner when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.
- The impact of any Ancillary Services not otherwise included in CBM or TRM.
- Post-backs of redirected or released Firm services.
- The impact of counter-flows not otherwise accounted for in the AFC calculation.
- The impact of any other services, contracts, or agreements not specified above using transmission that serves Native Load or Firm Network Integration Transmission Service
- The impact of any relevant third-party Firm Transmission Service that has not already been accounted for.

**R15.** The Transmission Service Provider shall limit the total impact of all Transmission Service from a specific source to not exceed sum of the nameplate ratings of all generators at that source.

**R16.** The Transmission Service Provider shall incorporate the following into relevant third-party Transmission Service:

- The transmission capability associated with serving the third-party's Native Load that impacts the Transmission Service Providers system by more than 3%.
- The impact of confirmed Network Integrated Transmission Service utilized on the third-party's system that impacts the Transmission Service Provider's system by more than 3%.
- The impact of confirmed Point to Point Transmission Service utilized on the third-party's system, based on expected source and sink, which does not source or sink within the Transmission Service Provider's own system and impacts the Transmission Service Provider's system by more than 3%.
- The impact of any roll-over rights on the third-party's system that impact the Transmission Service Provider's system by more than 3%.
- The impact of grandfathered Agreements on the third-party's system that impact the Transmission Service Provider's system by more than 3%.
- The impact of any required Ancillary Services not included in CBM or TRM on the third-party's system that impact the Transmission Service Provider's system by more than 3%.

**R17.** The Transmission Service Provider shall calculate non-firm AFC by reducing the TFC by the sum of the firm ETCs, the non-firm ETCs, and the TRM that the Transmission Service Provider has not elected to release allocated to the path.

**R18.** The Transmission Service Provider shall determine the impact of non-firm ETCs based on the following inputs:

- The impact of Non-Firm Network Integration Transmission Service serving Load, to include Load forecast error and losses not otherwise included in TRM or CBM.
- The impact of grandfathered non-firm Transmission Service Agreements and bundled contracts for energy and transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or Safe Harbor Tariff accepted by FERC.
- The impact of Non-firm Point to Point Transmission Service.
- The impact of counter flows not otherwise accounted for in the ATC calculation.
- Capacity utilized for TRM that the Transmission Service Provider has elected to be released for as non-firm ATC.
- Postbacks due to the reinstating of Firm from a "Firm-to-Non-Firm" redirect
- The impact of any relevant third-party Non-Firm Transmission Service that has not already been accounted for.

**R19.** For Point-to-Point Transmission Service where the source has not been specified, the Transmission Service Provider shall assume the source to be the adjacent Balancing Authority most electrically equivalent to the Point-of-Receipt.

**R20.** For Point-to-Point Transmission Service where the sink has not been specified, the Transmission Service Provider shall assume the sink to be the adjacent Balancing Authority most electrically equivalent to the Point-of-Delivery.

**R21.** The Transmission Service Provider shall make publicly available the results of the calculations of AFC upon calculation.

**R22.** The Transmission Service Provider shall covert Flowgate AFCs to path ATCs based on the following process:

*Flowgate(1), ... , Flowgate(n) = all Flowgates managed by a Transmission Service Provider*

*AFC of a Flowgate(n) impacted by a path, divided by the Distribution Factor for the path on the Flowgate(n) = "Partial ATC(n)"*

*ATC for a path = the lowest of all Partial ATC(1), ... , Partial ATC(n)*

- For each Flowgate honored by the Transmission Service Provider, the Transmission Service Provider shall calculate the partial AFC of that Flowgate by dividing the current AFC of that Flowgate by the path's power transfer distribution factor for that Flowgate.
- The Transmission Service Provider shall set the ATC for the path equal to the lowest of the partial AFCs of those Flowgates.

**R23.** The Transmission Service Provider shall increase non-firm ATC by the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC, to the extent allowable by the agreement associated with the service, in accordance with established business practices.

**R24.** The Transmission Service Provider shall make publicly available the ATC for each path.

## C. Compliance

To be added with next posting.

## D. Measures

To be added with next posting.

## E. Regional Differences

None.

## F. Associated Documents

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
| | | | |

Please use this form to submit comments on the 1st draft of standard MOD-030-1 Network Response Flowgate ATC. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| Individual Commenter Information<br>(Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the modeling standards to comply with the FERC directives and stakeholder recommendations.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-030-0 Network Response Flowgate ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-030-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**2.** Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**3.** Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**4.** Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**5.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**6.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☐ No

Comments:

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments:

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | APPA |
| **Lead Contact:** | **E. Nick Henery** |
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**1.** Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: These requirements should be in the FAC series and developed by personnel who are experienced in the determination of flowgates and their limitations. The requirements, as written are requiring improper use of the values stated in the requirements.

**2.** Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: These requirements are tariff or contract requirements that will be contained in or a part of a regulatory or legal document. Some of these requirements are not a reliability issues since and should be removed. Those statements that want to know the effects of actions that are of a reliability nature will be determined by other functions not the TSP, which just sell transmission capacity.

**3.** Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: Need to let the expanded SDT review this by personnel knowledgeable in development of AFT and distribution factors.

**4.** Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

☒ Yes

☐ No

Comments: This Standard trys to provide detail requirements for AFT, ATC, ETC and the requirements of 3 different functional entities and it is written in a manner that will not support a Compliance program.

**5.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings.
FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC.

**6.** Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☐ No

Comments:

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If “No,” please suggest how you believe the Order’s requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If “No,” please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☐ No

Comments:

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☐ No

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| Individual Commenter Information (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: Abbey Nulph | | |
| Organization: Bonneville Power Administration | | |
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| E-mail: ajnulph@bpa.gov | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority.

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The impact of load growth for Network Integration Transmission Service should be included in the second sub-bullet of R14.
   The "five years or longer in duration" language should be removed from the fifth sub-bullet of R14. due to the fact that this element of Order 890 is only to be implemented by a Transmission Service Provider (TSP) once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those existing Customers who have not yet been required to commit to five years of service to retain their roll-over rights.
   The ninth sub-bullet should include all other impacts and not just the impacts using transmission service to service Native Load or firm Network Integration load. Therefore, "using transmission that serves Native Load or Firm Network Integration Transmission Service" should be deleted.

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: However, for the reasons explained in our response to the MOD-030-1 Comment Form's question 4, BPA suggests that R22. be modified to the following:
   " The Transmission Service Provider shall make publicly available a mechanism for interested parties to convert Flowgate AFCs to path ATCs based on…"

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

   ☒ Yes

   ☐ No

Comments: Under the flowgate methodology, ATC is a value derived from an analysis of the expected powerflow impacts of a reservation across multiple flowgates. Consequently, it is the posting of AFC and timely posting of changes to AFC that inform whether transfer capability exists to support a request for transmission service. ATC for a POR-POD path is derived from posted AFC. When posting both ATC by path as well as AFC by Flowgate, there is a risk that the AFC and ATC values could get "out of sync" due to automation lag-time, etc. BPA believes that greater consistency and transparency is achieved if only AFC values are posted for each Flowgate, and requestors are provided with a "conversion calculator" that calculates ATC for their requested path based on posted AFC's.

**5.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**6.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority.

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☒ No

Comments: The threshold of 3% appears to be an arbitrary level. This level may be rooted in Operational and Planning studies that consider impacts from outages on one TP's system that increase loading on an element of another TP's system by 3% or more. While this level may be a good indicator of impact, it may not provide an indicator of which party's ownership or allocation of facilities is being used. It does not assure TPs will be able to preserve their rights (i.e. by contractual allocation) with a fixed threshold of 3%.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments: The ATC MODs (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide descriptions of these methodologies.

The Applicability section 4.1. through 4.3. should have the phrase "Available Transfer Capabilities for paths" replaced with "Available Flowgates Capabilities for Flowgates".

R1.2. should be modified due to the fact that Facilities don't cause congestion, rather they experience congestion. The following change to the language would be more accurate:

"How the methodology identifies transmisison Facilities that are expected by the AFC calculator to experience congestion on the transmission system."

R3. A Flowgate should not be defined as a thermal, voltage, or stability type due to the fact that Flowgates are limited by thermal, voltage, or stability problems that can vary depending on system conditions.

R4. through R8. should be combined into two requirements:

1) Each entity generating Flowgate limit values (note that it's not clear if this should be the Transmission Owner, Transmission Planner, Planning Coordinator, and/or Reliability Coordinator) shall provide current Flowgate limit data to Transmission Service Providers (TSPs); and

2) TSPs shall use the lesser of the thermal, voltage, or stability limits that apply to the current system conditions.

R18.-sub-bullet 5, R23., and R24. should each have the "ATC"s replaced with "AFC"s, for the reasons explained in our response to the MOD-030-1 Comment Form's question 4.

R24. should have "path" replaced with "Flowgate", for the reasons explained in our response to the MOD-030-1 Comment Form's question 4.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
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| Name: | Greg Rowland |
| Organization: | Duke Energy |
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| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

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| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☐ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

5. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: Conditional Firm Service (CFS) and Planning Redispatch Service (PRS) under Order No. 890 create new issues relating to modeling and calculating ATC. Specifically, when PRS is offered to maintain service, modeling for ATC calculations will be impacted during these periods. TTC must be modeled/calculated accounting for the new CFS/PRS requirements.

**6.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☐ No

Comments:

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments: R1.1 does not create the same level of transmission service as created in MOD-028. MOD 028 R6.1 involves N-1 transmission contingency AND ramping/partial contingency of generation. MOD-030 R1.1 appears to only require N-1 transmission or generation contingency. This is not comparable service.

For R3. need to also include why the Flowgate is a limit

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Narinder K. Saini | |
| Organization: | Entergy Services Inc. | |
| Telephone: | 870-543-5420 | |
| E-mail: | nsaini@entergy.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| George Bartlett | Entergy Services Inc. | **SERC** | Transmission Owner |
| Jim Case | Entergy Services Inc. | **SERC** | Transmission Owner |
| Ed Davis | Entergy Services Inc. | **SERC** | Transmission Owner |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the modeling standards to comply with the FERC directives and stakeholder recommendations.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-030-0 Network Response Flowgate ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-030-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: R5 reference to Transmission Operator should be changed to Transmission Owner.

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: Sub requirements shown as bullets should be changed to numbered subrequirements in R14, R16 and R18.

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The requirement should be worded in simple language to reflect how AFCs are determined rather than an equation that a program can use in developing program.

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: AFCs are not required to be posted as these do not mean much to the users, therefore, R21 should be deleted.

5. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

**6.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☒ Yes

☐ No

Comments:

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☒ Yes

☐ No

Comments:

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☒ No

Comments: The threshold level of 3% for third party should not be included in this standard since there is no such threshold level for Transmission Service Provider's own data.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments:

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| E-mail: smyers@ercot.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☒ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

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**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

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The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-030-0 Network Response Flowgate ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the ‘White Paper’ and MOD-030-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with “NRFG ATC Standard” in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: See IRC comments submitted by Charles Yeung.

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: See IRC comments submitted by Charles Yeung.

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: See comment 9.

5. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

**6.** Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If “No,” please suggest how you believe the Order’s requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If “No,” please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please the conflict in the comments area.

☒ Yes

☐ No

Comments: ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area and there has been no reservation of transmission capacity in ERCOT.

Available Transfer Capability is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. The ERCOT Interconnection has already moved “beyond” ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therfore both ERCOT and SPP are notified when the DC Tie capability is reduced.

Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.

In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.

In the current and future ERCOT market design the method of calculating ATC, TTC and the use of CBM and TRM are not applicable to the ERCOT Region. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Control Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments:

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| Name: | Dave Folk | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Richard Kovacs | FirstEnergy Corp. EDPP | | |
| Phil Bowers | FirstEnergy Corp. EDPP | | |
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1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments: However, the term "Post-backs" is industry jargon and should be replaced with the term "reinstatement" to add clarity.

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

☒ Yes

☐ No

Comments: The standard should include specifics of methods for complying with the term "publicly available" such as posting on OASIS, a corporate web page, etc. (This concept is mentioned in all MOD-028, MOD-029, and MOD-030.)

5. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities to whom you believe the standard should apply and why.

☒ Yes

☐ No

Comments: MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once, eliminate duplication, and simplify the applicability sections of MOD-028, 029, and 030

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If “No,” please suggest how you believe the Order’s requirements from paragraph 245 should be addressed in the comments area.

☒ Yes

☐ No

Comments: However, the phrase "not exceed" can be replaced with the word "the" since the term "limiting the total impact" is synonomous.

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If “No,” please specify what percent or alternate approach should be used and explain why in the comment area below.

☒ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please the conflict in the comments area.

☐ Yes

☒ No

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**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| Organization: IESO | | |
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| E-mail: ron.falsetti@ieso.ca | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
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| ☒ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the modeling standards to comply with the FERC directives and stakeholder recommendations.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If “No,” please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If “No,” please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: R14:
   It is not clear if the standard requires all inputs to be included in the calculation of the impact of Firm ETC. If so, 2 of bullet points are questionable:
   • FIRM NITS Reservations (second bullet point) are only explicitly incorporated in ETC if they cross control area boundaries. (POR not equal to POD) Otherwise they are part of the base-flow calculations - Designated Network Resources (DNRs) serving Native Load (first bullet point). In order to clarify, we could add to the second bullet: "not otherwise included in TRM or CBM or in the impacts of Native Load commitments"

   • Impact of Ancillary Services not included already in TRM, is very difficult to quantify and include in ETC.

   R18
   • Non-Firm ETC calculations use the same base flow based on resources serving native load commitments as Firm ETC Calculations. Non-Firm NITS Reservations (second bullet point) are only explicitly incorporated in ETC if they cross control area boundaries (POR not equal to POD). Otherwise they are part of the base-flow calculations.

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If “No,” please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: Yes, the conversion is described adequately.

   In the first bullet point, "…the Transmission Service Provider shall calculate the partial AFC of that…" should be written as "…the Transmission Service Provider shall calculate the partial ATC of that…"

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If “Yes,” please explain why in the comments area.

☒ Yes

☐ No

Comments: R21 and R24
Current tools allow the submission of requests and retrieval of available and calculated AFC and ATC data. It is questionable if that is considered being compliant with R21 and R24. If not, changes to the software might be required to meet the requirements of R21 and R24.

**5.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: Note - We don't have a complete overview of all directives to answer this question.

**6.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: TSP is the sole entity responsible for performing calculations, and posting of the results. The PC, RC, and TO only submit data to the TSP, such as list of OTDF and PTDF flow gates, seasonal limits of flow gates, flowgate components, flow directions on flowgate components etc. They do not calculate ATC, hence R1 is irrelevant.

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☒ No

Comments: No. R15 doesn't meet the intend of paragraph 245. Most of the PtP Reservations don't have specific resources as Source, they typically source from a group of commonly dispatched units. Also most Tariff's allow re-direct of Reservations to different Sources, so excluding Reservations from impact calculations could possibly result in overselling the system if the excluded reservation is re-directed to a different source. It might be possible to make some general guidelines to address the paragraph 245 of Order 890 such as:

• Total sum of Reservations (Confirmed, Approved, Study) impacting a specific corridor, such as a DC tie should not exceed the total capacity of the corridor.
• Total sum of Reservations (Confirmed, Approved, Study) sinking in a Control Area should not exceed the total Load of the Control Area.
• Total sum of Reservations ((Confirmed, Approved, Study) sourcing from a group of commonly dispatched units should not exceed the total available generation capacity of that group of units.

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☒ No

Comments: We assume the third party is a 1 tier or 2 tier Control Area adjacent to the Tariff footprint of the TSP. Some questions:
• Paragraph talks about impact transmission capability with 3%. Does this mean impact any flow gate within the Tariff footprint of the TSP with 3%. What about flow gates that are tie lines between Tariff footprint and 1tier and limiting element is in 1tier.
• What participation factors and generators should be used to determine if the GLDF of commonly dispatched units of 1tier Control Area is >3%. NERC IDC?
• Is the data listed in bullet point 2,3,4,5,6 of R16 going to be submitted by neighbor TSP. If so it is sufficient to specify that a TSP is getting the list of Reservations as specified in 2,3,4,5,6 of R16 from a neighboring TSP without having to know detail as specified in the bullet points.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments:

Please use this form to submit comments on the 1st draft of standard MOD-030-1 Network Response Flowgate ATC. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

| Group Comments (Complete this page if comments are from a group.) | |
|---|---|
| **Group Name:** | ISO RTO Council Standards Review Committee |
| **Lead Contact:** | **Charles Yeung** |
| **Contact Organization:** | **SPP** |
| **Contact Segment:** | **ISO RTO** |
| **Contact Telephone:** | **832-724-6142** |
| **Contact E-mail:** | **cyeung@spp.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Jim Castle | NYISO | **NPCC** | 2 |
| Alicia Daugherty | PJM | **RFC** | 2 |
| Ron Falsetti | IESO | **NPCC** | 2 |
| Matt Goldberg | ISO-NE | **NPCC** | 2 |
| Brent Kingsford | CAISO | **WECC** | 2 |
| Anita Lee | AESO | **WECC** | 2 |
| Steve Myers | ERCOT | **ERCOT** | 2 |
| William Phillips | MISO | **RFC+SERC+MRO** | 2 |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: R14:
   It is not clear if the standard requires all inputs to be included in the calculation of the impact of Firm ETC. If so, 2 of bullet points are questionable:
   • FIRM NITS Reservations (second bullet point) are only explicitly incorporated in ETC if they cross control area boundaries. (POR not equal to POD) Otherwise they are part of the base-flow calculations, DNR's serving Native Load. (first bullet point). Maybe add to second bullet: not otherwise included in TRM or CBM or in the impacts of Native Load commitments of first bullet point.
   • Impact of Ancillary Services not included already in TRM, is very difficult to quantify and include in ETC.

   R18
   • Non-Firm ETC calculations are using same base flow based on Resources serving Native Load commitments as Firm ETC Calculations. The base flow calculations don't make a distinguishion between Non-Firm or Firm, only if part of the Native Load is supplied by DNR from outside the Control Area. Non-Firm NITS Reservations (second bullet point) are only explicitly incorporated in ETC if they cross control area boundaries. Otherwise they are part of the base-flow calculations.

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: Yes, conversion described adequate.
   • Partial AFC should be partial ATC in first bullet point.

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

   ☒ Yes

☐ No

Comments: R21 and R24
Current tools allow to submit test requests and get AFC and ATC data available. It is questionable if that is considered being compliant with R21 and R24. If not, changes to software are required to meet the requirements of R21 and R24.

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☐ Yes

☒ No

Comments: Note - Don't have a complete overview of all directives to answer that question. This is time intensive!!!!

6. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: TSP is responsible to perform calculations, and post the results, the PC and RC and TO only submit data to TSP, such as list of flow gates, limits of flow gates. They do not calculate ATC, hence R1 is irrelevant.

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☐ Yes

☒ No

Comments: No R15 doesn't meet the intend of paragraph 245. Most of the PtP Reservations don't have specific resources as Source, they typically source from a group of commonly dispatched units. Also most Tariff's allow re-direct of Reservations to different Sources, so excluding Reservations from impact calculations could possibly result in overselling the system if the excluded reservation is re-directed to a different source. It might be possible to make some general guidelines to address the paragraph 245 of Order 890 such as:

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8. Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☒ No

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☐ Yes

☐ No

Comments:

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Comments:

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Brian Thumm | | |
| Organization: ITC | | |
| Telephone: 248-374-7846 | | |
| E-mail: bthumm@itctransco.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| Group Comments (Complete this page if comments are from a group.)<br>**Group Name:**<br>**Lead Contact:**<br>**Contact Organization:**<br>**Contact Segment:**<br>**Contact Telephone:**<br>**Contact E-mail:** | | | |
|---|---|---|---|
| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If “No,” please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: ITC agrees with the requirements, themselves, but disagrees with the responsible entities. The Transmission Owner and/or Transmission Operator should be responsible for determing all limits (thermal, voltage, stability) of the transmission facilities. The TO/TOP may choose to delegate the activities, but the requirements in this Standard have put the responsibility on the wrong entity. The RC should not be involved in the determination of facility limits unless so designated to do so. R4 and R5 are appropriate in that respect, but the others are not. As a Transmission Owner/Operator, ITC would be object to any rating greater than one we would provide. This is a dangerous possibility as currently written particularly if commericial interests could affect reliability considerations.

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If “No,” please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: It is not clear that any "allocations" of flowgate capacity, such as in the MISO/PJM Seams agreement, are covered here. These allocations, while technically covered by the 2nd to last bullet, need to be addressed by stronger language than a blanket "any other agreements" clause.

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If “No,” please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The conversion of AFC to ATC is covered, but it is not clear. The original SAR for this standard included a white paper with appropriate coversion formulae. Please consult and include the translation equations.

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If “Yes,” please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: A ridiculous amount of paper or web space will be used if all ATC path values are posted for large footprints. Flowgates can be in the thousands but ATC paths are quadratic functions of the number of Sources/Sinks (ie, too many paths to print). ATC for a given path should be on request. (i.e., ask for the path and the TSP provides that specific path ATC via

OASIS). This should be either through manual entry by the requestor or electronically via a requestor electronic query tool (i.e., computer program query).

**5.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**6.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: Applicable Entity 4.2 is not appropriate. Reliability Coordinators should not be calculating ATC. According to the Functional Model, ATC Calculations are performed by the Transmission Service Provider (Task #2, "Determine and post available transfer capability values.") R4 and R5 identify the TO and TP as responsible entities, and need to be included in the applicability sections.

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☒ No

Comments: It meets the intent but is subject to potentiallt adverse interpretation. It is true that a POR may not exceed Pmax for the installed generation; however, when multiple requests are received for the POR that exceed Pmax, should the requests be taken first-come-first-served until Pmax is reached? Should the worst-case scenario be studied and used to set limits? Should the requests be pro-rated until the sum of the requests is reduced to Pmax? We believe the TSP should be allowed some leeway in how they model these situations, in order to prevent reliability problems.

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☒ Yes

☐ No

Comments: This is overdue in our estimation. Using 5%, as some have done, has resulted in unnecessary TLRs, particularly on lower voltage (138kV and below) systems.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☒ No

Comments: There are 3 methods, pick the one that works. We have noted in our other comments that some entities, such as New England, have approved tariffs that don't require the sale of transmission service. They should not have to pick any method but should, as we have noted, be required to provide data to neighboring TSPs that do sell transmission service.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments: We think this is a much better standard than MOD-028 and -029. It should provide for greater flexibility and reliability. We think all methods should be examined closely if there is any evidence of overselling (as evidenced byTLRs and market congestion) or underselling (as evidenced by denial of service without TLRs or market congestion).

Please use this form to submit comments on the 1st draft of standard MOD-030-1 Network Response Flowgate ATC. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: Dennis Kimm | | |
| Organization: MidAmerican Energy Generation/Trading | | |
| Telephone: 515 252 6737 | | |
| E-mail: ddkimm@midamerican.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☒ **MRO** | ☐ | 3 — Load-serving Entities |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the modeling standards to comply with the FERC directives and stakeholder recommendations.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-030-0 Network Response Flowgate ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-030-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments: The functional model doesn't necessarily translate to reality so this is hard to answer.

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

5. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: Standard is a fill-in-the-blank

**6.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☐ No

Comments:

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☒ Yes

☐ No

Comments: The words meet the intent of the order, but the order may not be technically correct, nor constistent with other OATT requirements.

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☒ No

Comments: If is this appropriate for MOD-30, it is appropriate for MOD-28. Why do you specifically spell out a requirement for MOD-30 but not MOD-28?

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☒ Yes

☐ No

Comments: This standard is not requiring consistenecy per the requirement of FERC Order 890.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments: This MOD should be combined with MOD-28 and everyone using a distribution factor based analysis should use the same methodology and the amount of constistency should be increased significantly.

Please use this form to submit comments on the 1st draft of standard MOD-030-1 Network Response Flowgate ATC. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Tom Mielnik | |
| Organization: | MidAmerican Energy Company | |
| Telephone: | 563-333-8129 | |
| E-mail: | tcmielnik@midamerican.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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The standard drafting team was charged with revising the modeling standards to comply with the FERC directives and stakeholder recommendations.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: For R6, R8, R9, R10, R11 the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. Further R1 and R2 should also be revised for this reaons to also refer to the "Transmission Service Provider, the Reliabiltiy Coordinator and/or the Planning Coordinator, as appropriate."

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: 1. R1.1, R3, R11and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration. 2. R14 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropriate level of " the following inputs. 3. R16 the impacts by more than 3% are consistent with post-contingent flowgates. It should be noted that there are continuing to exist in the area, pre-contingent flowgates which would be inproperly represented by post-contingent flowgates. The pre-contingent flowgates in the area generally only consider signficant third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent. 4. R18 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the area to maximize the non-firm offerings in the operating horizon. I suggest wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC." 5. Either use existing transmission commitments in lower case or else provide a definition for the NERC Glossary.

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The R22 is inadequate in describing what must be done. It is unclear what path the flowgates are to be converted to. Are the flowgate quantities to be converted into equivalent control area to control area path quantities? Are the flowgate quantities to be converted into flowgate path quantities? If it is the latter, what are the definitions and purposes of the flowgate path quantities? In addition, I do not understand what the benefits are in converting Flowgate AFCs to path AFCs. It seems to be an unnecessary and confusing requirement albeit one in FERC Order 890.

**4.** Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

☒ Yes

☐ No

Comments: It will be incredibly confusing posting both AFCs and ATCs for the same transmission service. I agree that this is in accordance with the FERC Order 890; however, I do not understand what the benefits of this conversion to open transmission service and reliability. I ask the SDT to clarify.

**5.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: It is not appropriate to qualify the Functional Entity as provided in A.4.1 through A.4.3, that is, A.4.1 through A.4.3 should just list the NERC functions from the NERC functional model and not qualify it. For example, 4.1 should be "Planning Coordinator" not "Each Planning Coordinator that uses the Flowgate Network Response method to calculate…..". Then it is up to Planning Coordinators etc. to review the standard to see how the requirements are to be applied, if at all.

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☒ Yes

☒ No

Comments: The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests to the source point where subsequent requests will result in power being moved away from the point and show how the Transmission Service Provider than reviews the impacts to meet the requirement.

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☒ No

Comments: The impacts by more than 3% are consistent with post-contigent flowgates. It should be noted that pre-contingent flowgates are continuing to exist in the area. Such pre-contingent flowgates have physical conditions that would be improperly represented by post-contingent flowgates so the pre-contingent flowgates must remain in place. The pre-contingent flowgates in the area generally only consider signficant those third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments: 1. R1.1 implies that the only planning criteria that should be used in ATC calculations is Category B in Table 1 of the NERC Standards. That is incorrect, the methodology should describe how it meets the planning criteria that is appropriate for posted values including applicable NERC Standards, regional criteria, Transmission Owner criteria, etc. Therefore, R1.1 should state that "How methodology meets the planning criteria in NERC Standards, regional standards, Transmission Owner's planning criteria, Transmission Planner's planning criteria, and other applicable planning criteria used by the Transmission Planner to plan the system. 2. R8 does not cover all the limitations that are possible for flowgates, for example, the limitation may be due to high transfers causing low voltage on the system after the next condition. This is not an example of a thermal rating or a voltage limit of the power transfer. I suggest that an additional bullet be added to R8 stating "Any other constraint to power transferred across the Flowgate, if applicable. For such constraints, the constraint should be defined, explained, and examples given in the methodology so as to ensure that the ATC methodology is transparent." As an alternative, a bullet should be added for "Steady-state voltage constraint." 3. The scheduling time horizon should be clarified. 4. The Standards Drafting Team indicated that they have decided not to define the term Existing Transmission Commitments, yet R13 uses that defined term with capital letters. The words Existing Transmission Commitments in R13 and elsewhere in the standard should not be capitalized so as not to indicate a defined term. 5. R22 change "covert" to "convert".

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| **Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Michelle Rheault | | |
| Organization: Manitoba Hydro | | |
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| E-mail: mdrheault@hydro.mb.ca | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: I don't believe there should be a conversion it only leads to uncertainty. I believe that the committee should be able to standardize on one technique.

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

   ☐ Yes

   ☐ No

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   ☐ No

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☒ Yes

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☐ Yes

☐ No

Comments:

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☒ No

Comments: During a TLR or redispatch, a 3% cutoff would require the third party to adjust their resources by up to 33 MW for every 1MW of relief. I believe that this is too much. I would recommend third party mitigation has to be a balance of impact and ability for relief and that 3% biases that balance. I would recommend that the 5% impact which still requires a potential 20 MW adjustment for every 1 MW of relief maintains the balance between impact and ability for relief.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☒ No

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<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☐ NPCC<br>☐ RFC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
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<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

| Group Comments (Complete this page if comments are from a group.) | |
|---|---|
| **Group Name:** | Midwest Reliability Organization (MRO) |
| **Lead Contact:** | **Tom Mielnik** |
| **Contact Organization:** | **MRO for Group (MEC for Lead Contact)** |
| **Contact Segment:** | **10** |
| **Contact Telephone:** | **563-333-8129** |
| **Contact E-mail:** | **tcmielnik@midamerican.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Neal Balu | WPS | **MRO** | 10 |
| Terry Bilke | MISO | **MRO** | 10 |
| Robert Coish, Chair | MHEB | **MRO** | 10 |
| Carol Gerou | MP | **MRO** | 10 |
| Ken Goldsmith | ALT | **MRO** | 10 |
| Todd Gosnell | OPPD | **MRO** | 10 |
| Jim Haigh | WAPA | **MRO** | 10 |
| Joe Knight | GRE | **MRO** | 10 |
| Pam Oreschnick | XEL | **MRO** | 10 |
| Dave Rudolph | BEPC | **MRO** | 10 |
| Eric Ruskamp | LES | **MRO** | 10 |
| 28 Additional MRO Members | Not Named Above | **MRO** | 10 |
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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The MRO believes that for R6, R8, R9, R10, R11 the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. Further R1 and R2 should also be revised for this reaons to also refer to the "Transmission Service Provider, the Reliabiltiy Coordinator and/or the Planning Coordinator, as appropriate."

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: 1. R1.1, R3, R11and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration. 2. R14 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropraite level of " the following inputs. 3. R16 the impacts by more than 3% are consistent with post-contingent flowgates. It should be noted that there are continuing to exist in the MRO area, pre-contingent flowgates which would be inproperly represented by post-contingent flowgates. The pre-contingent flowgates in the MRO generally only consider signficant third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent. 4. R18 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the MRO to maximize the non-firm offerings in the operating horizon. The MRO suggests wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC." 5. Either use existing transmission commitments in lower case or else provide a definition for the NERC Glossary.

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The MRO believes that the R22 is inadequate in describing what must be done. It is unclear what path the flowgates are to be converted to. Are the flowgate quantities to be converted into equivalent control area to control area path quantities?  Are the flowgate quantities to be converted into flowgate path quantities?  If it is the latter, what are the defintions and purposes of the flowgate path quantities?  In addition, the MRO does not understand what the benefits are in converting Flowgate AFCs to path AFCs.  It seems to be an unnecessary and confusing requirement albeit one in FERC Order 890.

**4.** Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard?  If "Yes," please explain why in the comments area.

☒ Yes

☐ No

Comments: It will be incredibly confusing posting both AFCs and ATCs for the same transmission service.  The MRO agrees that this is in accordance with the FERC Order 890; however, the MRO does not understand what the benefits of this conversion to open transmission service and reliability.  The MRO asks the SDT to clarify.

**5.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC.  Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1?  If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

6. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: The MRO believes it is not appropriate to qualify the Functional Entity as provided in A.4.1 through A.4.3, that is, the MRO recommends that A.4.1 through A.4.3 just list the NERC functions from the NERC functional model and not qualify it. For example, 4.1 should be "Planning Coordinator" not "Each Planning Coordinator that uses the Flowgate Network Response method to calculate…..". Then it is up to Planning Coordinators etc. to review the standard to see how the requirements are to be applied, if at all.

7. In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☒ Yes

☒ No

Comments: The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests to the source point where subsequent requests will result in power being moved away from the point and show how the Transmission Service Provider than reviews the impacts to meet the requirement.

8. Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☒ No

Comments: The impacts by more than 3% are consistent with post-contigent flowgates. It should be noted that pre-contingent flowgates are continuing to exist in the MRO area. Such pre-contingent flowgates have physical conditions that would be improperly represented by post-contingent flowgates so the pre-contingent flowgates must remain in place. The pre-contingent flowgates in the MRO generally only consider signficant those third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent.

9. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments: 1. R1.1 implies that the only planning criteria that should be used in ATC calculations is Category B in Table 1 of the NERC Standards. That is incorrect, the methodology should describe how it meets the planning criteria that is appropriate for posted values including applicable NERC Standards, regional criteria, Transmission Owner criteria, etc. Therefore, R1.1 should state that "How methodology meets the planning criteria in NERC Standards, regional standards, Transmission Owner's planning criteria, Transmission Planner's planning criteria, and other applicable planning criteria used by the Transmission Planner to plan the system. 2. R8 does not cover all the limitations that are possible for flowgates, for example, the limitation may be due to high transfers causing low voltage on the system after the next condition. This is not an example of a thermal rating or a voltage limit of the power transfer. The MRO suggests that an additional bullet be added to R8 stating "Any other constraint to power transferred across the Flowgate, if applicable. For such constraints, the constraint should be defined, explained, and examples given in the methodology so as to ensure that the ATC methodology is transparent." As an alternative, the MRO recommends that a bullet be added for "Steady-state voltage constraint." 3. MRO believes the scheduling time horizon should be clarified. 4. The Standards Drafting Team indicated that they have decided not to define the term Existing Transmission Commitments, yet R13 uses that defined term with capital letters. The words Existing Transmission Commitments in R13 and elsewhere in the standard should not be capitalized so as not to indicate a defined term. 5. R22 change "covert" to "convert".

Please use this form to submit comments on the 1st draft of standard MOD-030-1 Network Response Flowgate ATC. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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|---|---|
| Group Comments (Complete this page if comments are from a group.) | |
| **Group Name:** | Public Service Commission of South Carolina |
| **Lead Contact:** | **Phil Riley** |
| **Contact Organization:** | **Public Service Commission of South Carolina** |
| **Contact Segment:** | **9** |
| **Contact Telephone:** | **803-896-5154** |
| **Contact E-mail:** | **philip.riley@psc.sc.gov** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mignon L. Clyburn | PSCSC | **SERC** | 9 |
| G. O'Neal Hamilton | PSCSC | **SERC** | 9 |
| John E. "Butch" Howard | PSCSC | **SERC** | 9 |
| Randy Mitchell | PSCSC | **SERC** | 9 |
| C. Robert "Bob" Moseley | PSCSC | **SERC** | 9 |
| David A. Wright | PSCSC | **SERC** | 9 |
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1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

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   ☒ Yes

   ☐ No

   Comments:

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☒ Yes

☐ No

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Comments:

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☐ Yes

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| Group Comments (Complete this page if comments are from a group.) | | | |
|---|---|---|---|
| **Group Name:** | SERC Available Transfer Capability Working Group (ATCWG) | | |
| **Lead Contact:** | **John Troha** | | |
| **Contact Organization:** | **SERC Reliability Corporation** | | |
| **Contact Segment:** | **10 - RRO** | | |
| **Contact Telephone:** | **704-948-0761** | | |
| **Contact E-mail:** | **jtroha@serc1.org** | | |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Darrell Pace | Alabama Electric Cooperative, Inc | **SERC** | 10 |
| Helen Stines | Alcoa Power Generating, Inc. | | |
| Eugene Warnecke | Ameren | | |
| Don Reichenbach | Duke | | |
| Joachim Francois | Entergy | | |
| Ross Kovacs | Georgia Transmission Corporation | | |
| Larry Middleton | Midwest ISO | | |
| Jerry Tang | Municipal Electric Authority of Georgia | | |
| John Troha | SERC Reliability Corporation | | |
| Al McMeekin | South Carolina Electric and Gas Company | | |
| Stan Shealy | South Carolina Electrica nd Gas Company | | |
| Carter Edge | SERC Reliability Corporation | | |
| DuShaune Carter | Southern Company Services, Inc. -Trans | | |
| Bryan Hill | Southern Company Services, Inc. -Trans | | |
| Doug Bailey | Tennessee Valley Authority | | |
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*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: see answer to #6.

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The definition provided in the SAR was clearer than the current definition. The new definition introduces new terms into the process that are not industry standard or recognizable.

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: Posting the AFC numbers provide no additional value if the ATC numbers are posted.

5. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

6. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: The applicability section needs clarification. Referencing R1,6,8,9 and 10 they should apply only to those entities performing the function. The standard should not require the calculations be made by the PC and RC, but should be applicable to the designated entitiy performing these calculations . The designated entity must be specified as a requirement in this standard. For example: The TSP, PC and RC must specify and agree to the entity that performs this function in the TSP's ATCID as required in MOD 1. The current revision of MOD-001 states the following requirement as R1: "Each Transmission Service Provider, and its associated Planning Coordinators and Reliability Coordinators, shall agree upon and implement one or more of the ATC methodologies specified in Reliability Standard MOD-028, MOD-029, and MOD-030 for use in determining Transfer Capabilities of those Facilities under the tariff administration of that Transmission Service Provider." The requirements of MOD-0028 should refer to the Designated Entity specified through this requirement. The following are examples of how this would be implemented in the standard:

B. Requirements
R4. Each Designated Entity shall ensure that the Total Transfer Capability (TTC) for each of its Transmission Service Provider's POR to POD Paths is calculated and up-to-date for use within the Transfer Capability time horizons specified in MOD-001 R2.
R5. Prior to calculating TTC, each Designated Entity shall update the following components of the base case power flow model it uses to calculate TTC for the time horizon being studied:

7. In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

8. Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☐ No

Comments:

9. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments: The updating of flowgates as specified in Requirement 2 should be annually rather than quarterly.

Please use this form to submit comments on the 1st draft of standard MOD-030-1 Network Response Flowgate ATC. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with “NRFG ATC Standard” in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | W. Shannon Black Et Al ; Sacramento Municipal Utility District | |
| Organization: | Sacramento Municipal Utility District | |
| Telephone: | (916) 732-5734 | |
| E-mail: | sblack@smud.org | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | WECC MIC MIS ATC TF |
| **Lead Contact:** | **W. Shannon Black** |
| **Contact Organization:** | **Sacramento Municipal Utility District** |
| **Contact Segment:** | **Various** |
| **Contact Telephone:** | **(916) 732-5734** |
| **Contact E-mail:** | **sblack@smud.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| The 24 individuals listed in this same section for MOD-01 comments, filed jointly with this filing, by the WECC MIC MIS ATC TF Team, have either actively monitored this work product or have actively engaged in drafting the attached comments. That Team list of 24 individuals applies to jointly to MOD-01; MOD-04; MOD-08; MOD-29 and MOD-30. | | | |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the modeling standards to comply with the FERC directives and stakeholder recommendations.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-030-0 Network Response Flowgate ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-030-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: "Planning Coordinator" is not a defined term. Pleae correct.

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The impact of load growth for Network Integration Transmission Service should be included in the second sub-bullet of R14.

   The "five years or longer in duration" language should be removed from the fifth sub-bullet of R14. due to the fact that this element of Order 890 is only to be implemented by a TSP once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those exisitng Customers who have not yet been required to commit to five years of service to retain their roll-over rights.

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments: No comment.

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:
   (The below statement is proposed by BPA. Is the WECC Team OK with supporting it?)

Under the flowgate methodology, ATC is a value derived from an analysis of the expected powerflow impacts of a reservation across multiple flowgates. Consequently, it is the posting of AFC and timely posting of changes to AFC that inform whether transfer capability exists to support a request for transmission service. ATC for a POR-POD path is derived from posted AFC. When posting both ATC by path as well as AFC by flowgate, there is a risk that the AFC and ATC values could get "out of sync" due to automation lag-time, etc. BPA believes that greater consistency and transparency is achieved if only AFC values are posted for each flowgate, and requestors are provided with a "conversion calculator" that calculates ATC for their requested path based on posted AFC's.

**5.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments: No comment.

**6.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☐ No

Comments: See above on defining Planning Coordinatior.

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☒ Yes

☐ No

Comments:

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☒ No

Comments: The threshold of 3% appears to be an arbitrary level. This level may be rooted in Operational and Planning studies that consider impacts from outages on one TP's system that increase loading on an element of another TP's system by 3% or more. While this level may be a good indicator of impact, it may not provide an indicator of which party's ownership or allocation of facilities is being used. It does not assure TPs will be able to preserve their rights (i.e. by contractual allocation) with a fixed threshold of 3%.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments:

A.

R1.2 should be modified due to the fact that Facilities don't cause congestion, rather they experience congestion. The following change to the language would be more accurate:

"How the methodology identifies transmisison Facilities that are expected by the AFC calculator to experience congestion on the transmission system."

B.

See comments on MOD-29.

In the "Applicability" section, the term "Available Transfer Capability Implementation Document" is used as a defined term. The term is used in MOD-01 R3. At minimum the ATCID either needs to be defined or a reference to the MOD-01 must be inserted for cross reference.

C.

R.1 through R.3. appear to be a prohibited "fill-in-the-blank."

D.

R22. Typo. Change "covert" to "convert."

Please use this form to submit comments on the 1st draft of standard MOD-030-1 Network Response Flowgate ATC. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: Chuck Falls | | |
| Organization: Salt River Project | | |
| Telephone: 602 236-0965 | | |
| E-mail: Chuck.Falls@srpnet.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the modeling standards to comply with the FERC directives and stakeholder recommendations.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-030-0 Network Response Flowgate ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-030-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NRFG ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

5. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

**6.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☐ No

Comments:

**7.** In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

**8.** Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

Comments:

The standard should describe how flowgates and reliability limits should be determined such as is done for the Network Response Methodology MOD028 in requirement R6 and is done for the Rated System Path Methodology MOD029 in requirement R6.

Requirements R1.1, R1.2 & R1.3 are fill-in-the-blank requirements and need to specify rather than ask the tsp to explain what they do.

R8 - The standard should specify how the thermal, voltage and stability limited are determined. For example, are these n-0 or n-1 limits and are they transient or post-transient?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

**Consideration of Comments on 1st Draft of Standard MOD-030-1 — Network Response Flowgate ATC (Project 2006-07)**

The ATC Standard Drafting Team requesters thank all commenters who submitted comments on the first draft of standard MOD-030-1, Network Response Flowgate ATC (Project 2006-07). This standard was posted for a 30-day public comment period from May 25 through June 24, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 17 sets of comments, including comments from 83 different people from more than 40 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received from stakeholders, comments from the cooperative effort with NAESB in developing associated business practices, and comments received from FERC staff, the drafting team has significantly redrafted the standard. The changes have been so extensive that the revised standard bears very little resemblance to the last posted draft. Major changes include:

- Added definitions for the following terms:
  - Flowgate
  - Total Flowgate Capability
  - Available Flowgate Capability
  - Power Transfer Distribution Factor
  - Outage Transfer Distribution Factor
  - Flowgate Methodology
- Changed the title of the standard to just, 'Flowgate Methodology'
- Modified the purpose to clarify that the intent is to support 'consistency and transparency of transfer capability calculations' rather than 'consistency and uniformity of ATC calculations'
- Modified the applicability so that the requirements apply to the Transmission Service Provider and the Transmission Operator – the Planning Coordinator and Reliability Coordinator were removed as applicable entities
- R1 was revised so that, instead of being assigned to the Planning Coordinator and Reliability Coordinator, R1 in the revised standard applies to the Transmission Service Provider to align with the revisions made to MOD-001 – Available Transfer Capability – where responsibility for the Available Transfer Capability Identification Document is assigned to the Transmission Service Provider. The sub-requirements were removed and added to R2.
- R2 was revised so that instead of he Planning Coordinator and Reliability Coordinator identifying Flowgates based on criteria in R1, the requirement was assigned to the Transmission Operator, and the criteria in R1 (sub-bullets R1.1 through R1.3) were clarified and added to R2. R2 was expanded to include the process for identifying Flowgates.
- R3 – was a requirement to make Flowgates 'publicly available' and this has been deleted. NAESB business practices will address all posting requirements. The NERC reliability standards stop at the point where the data or information is provided to the entity responsible for the posting.

- R4 was deleted from the revised standard. This requirement was assigned to the Transmission Owner and Transmission Planner and required that limits be provided to the Transmission Service Provider for use in determining Total Flowgate Capability. Since the standard was revised and the responsibility for determining TFC is now assigned the Transmission Operator this requirement is no longer needed as the Transmission Operator should already have these limits.
- R5 was a requirement for the Transmission Service Provider to use specific thermal limits in the determination of TFC. This requirement was merged into R2 and is assigned to the Transmission Operator. (See R2.3 in the revised standard.)
- R6 was deleted from the revised standard. R6 required the Planning Coordinator ad Reliability Coordinator to provide the Transmission Service Provider with voltage and stability limits – the revised standard assigns the Transmission Operator responsibility for determining TFCs, and assumes that the Transmission Operator already has these limits.
- R7 was a requirement for the Transmission Service Provider to use specific voltage and stability limits in the determination of TFC. This requirement was merged into R2 and is assigned to the Transmission Operator. (See R2.3 in the revised standard.)
- R8 was a step in the determination of TFC and had been assigned to the Planning Coordinator and Reliability Coordinator. In the revised standard this requirement is assigned to the Transmission Operator (see R2.3 in the revised standard)
- R9 required the Planning Coordinator and Reliability Coordinator to ensure TFCs were calculated in accordance with various time periods. In the revised standard, the Transmission Operator is responsible for calculating TFCs. (see R2.4 in the revised standard)
- R10 required the Planning Coordinator and Reliability Coordinator to distribute their TFCs, and in the revised standard this requirement is assigned to the Transmission Operator. (see R2.5 in the revised standard)
- R11 required public posting of TFCs and this requirement has been deleted from the revised standard. All ATC-related posting requirements are being addressed by NAESB in business practices.
- R12 was a requirement to calculate AFC at specific intervals and this is now addressed in MOD-001 — Available Transfer Capability.
- R13 was a requirement to determine Firm AFC and this has been revised to add more specificity. In the revised standard this is R8 and includes a specific algorithm for determining Firm AFC, with each element of the algorithm clearly defined.
- R14 identified the 'inputs' to use to determine the impact of firm ETC and this has been revised to require the calculation of the impact of firm ETC based on specific time periods. Much more specificity has been added to the description of this process. See R6 in the revised standard.
- R15 required the Transmission Service Provider to limit the total impact of all transmission service from a specific resource to not exceed the sum of the nameplate ratings of all generators at that source. The drafting team could not find a reliable approach to specifying how this could be implemented and the requirement was deleted.
- R16 was modified such that the 3% specified for including third party impacts applies only to 1st tier TSPs and those TSPS with which coordination agreements have been

executed. The elements of this requirement have been moved into R6 and R7 in the revised standard.

- R17 identified a process for calculating non-firm AFC and this has been revised. In the revised standard the process has been converted into an algorithm with each element in the algorithm clearly defined. See R9 in the revised standard.
- R18 identified the 'inputs' to use to determine the impact of non-firm ETC and this has been revised to require the calculation of the impact of ETC on non-firm commitments. See R6 in the revised standard.
- R19 and R20 required specific criteria be met in the modeling of the source and sink, and these requirements were merged into the modeling requirements for the Transmission Service Provider's calculation of AFC. See R4 in the revised standard.
- R21 was a requirement to make AFC calculation results 'publicly available' and this requirement has been deleted from the revised standard because it is being addressed by NAESB in a business practice.
- R22 was a requirement to convert AFC to ATC and this has been modified so that in the revised standard, the process for this conversion is addressed with an algorithm where each element of the algorithm is clearly defined. See R 10 in the revised standard.
- R23 was removed because the release of unscheduled Transmission Service for resale will be addressed by NAESB.
- R24 was a requirement to make ATC 'publicly available' and this requirement has been deleted from the revised standard because it is being addressed by NAESB in a business practice.
- Measures and compliance elements were added.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Anita Lee (G2) | AESO | | ✓ | | | | | | | | |
| 2. | Jason Murray (G6) | AESO | | ✓ | | | | | | | | |
| 3. | Darrell Pace (G4) | Alabama Electric Coop. Inc | | | | ✓ | ✓ | ✓ | | | | |
| 4. | Helen Stines (G4) | Alcoa Power Generating Inc. | | | | | | ✓ | ✓ | ✓ | | |
| 5. | Ken Goldsmith (G3) | ALT | ✓ | | | | ✓ | | | | | |
| 6. | Eugene Warnecke (G4) | Ameren | | | ✓ | | | ✓ | | | | |
| 7. | E. Nick Henery (G1) | APPA | ✓ | | | | | | | | | |
| 8. | Jerry Smith (G6) | APS-TP | | | | | | | | | | |
| 9. | Dave Rudolph (G3) | BEPC | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 10. | Steve Tran (G6) | BP TX | | | | | | | | | | |
| 11. | Abbey Nulph (I) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 12. | Abbey Nulph (G6) (I) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 13. | Rebecca Berdahl (G6) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 14. | Steve Knudsen (G6) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 15. | Charles Mee (G6) | CA Dept Water & Power | | | | | | | | | | |
| 16. | Brent Kingsford (G2) | CAISO | | ✓ | | | | | | | | |
| 17. | Greg Ford (G6) | CISO-TP | | ✓ | | | | | | | | |
| 18. | Don Reichenbach (G4) | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 19. | Greg Rowland | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 20. | Ed Davis | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 21. | George Bartlett | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 22. | Jim Case | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 23. | Joachim Francois (G4) | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 24. | Narinder K. Saini | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 25. | Steve Myers (I) (G2) | ERCOT | | ✓ | | | | | | | | ✓ |
| 26. | Patricia vanMidde (G6) | FERC Case MRG, Sempra | | | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 27. | Dave Folk | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 28. | Phil Bowers | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 29. | Richard Kovacs | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 30. | Ross Kovacs (G4) | Georgia Transmission Co. | ✓ | | ✓ | | | | | | | |
| 31. | Joe Knight (G3) | Great River Energy | ✓ | | ✓ | | ✓ | | | | | |
| 32. | Ron Falsetti (I) (G2) | IESO | | ✓ | | | | | | | | |
| 33. | Lou Ann Westerfield (G6) | IPUC-SP | | | | | | | | | | |
| 34. | Charles Yeung (G2) | IRC | | ✓ | | | | | | | | |
| 35. | Matt Goldberg (G2) | ISO New England | | ✓ | | | | | | | | |
| 36. | Brian Thumm | ITC | ✓ | | | | | | | | | |
| 37. | Sueyen McMahon (G6) | LADWP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 38. | Eric Ruskamp (G3) | Lincoln Electric System | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 39. | Michelle Rheault | Manitoba Hydro EB | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 40. | Robert Coish (G3) | Manitoba Hydro EB | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 41. | Jerry Tang (G4) | MEAG | ✓ | | ✓ | | ✓ | | | | | |
| 42. | Tom Mielnik (I) (G3) | MidAmerican (MEC) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 43. | Dennis Kimm | MidAmerican (MEC) Trading | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 44. | Larry Middleton (G4) | Midwest ISO | | ✓ | | | | | | | | |
| 45. | Carol Gerou (G3) | Minnesota Power | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 46. | Terry Bilke (G3) | MISO | | ✓ | | | | | | | | |
| 47. | William Phillips (G2) | MISO | | ✓ | | | | | | | | |
| 48. | Jim Castle (G2) | New York ISO | | ✓ | | | | | | | | |
| 49. | Matt Schull (G1) | North Carolina MPA | | | ✓ | ✓ | ✓ | ✓ | | | | |
| 50. | Todd Gosnell (G3) | OPPD | ✓ | | ✓ | | | ✓ | | | | |
| 51. | Brian Weber (G6) | Pacificorp | ✓ | | | | ✓ | | | | | |
| 52. | Alicia Daugherty (G2) | PJM | | ✓ | | | | | | | | |
| 53. | C. Robert Moseley (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 54. | David A. Wright (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 55. | G. O'Neal Hamilton (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 56. | John E. Howard (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 57. | Mignon L. Clyburn (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 58. | Phil Riley (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 59. | Randy Mitchell (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 60. | Chuck Falls (I) (G6) | Salt River Project (SRP) | ✓ | | | | | | | | | |
| 61. | Al McMeekin (G4) | SC Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |
| 62. | Stan Shealy (G4) | SC Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 63. | Bryan Hill (G4) | SCS- Trans | ✓ | | | | ✓ | | | | | |
| 64. | DuShaune Carter (G4) | SCS -Trans | ✓ | | | | ✓ | | | | | |
| 65. | John Troha (G4) | SERC ATCWG | | | | | | | | | | ✓ |
| 66. | Carter Edge (G4) | SERC RC | | | | | | | | | | ✓ |
| 67. | Bob Schwermann (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 68. | Brian Jobson (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 69. | Dick Buckingham (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 70. | Dilip Mahendra (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 71. | W. Shannon Black (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 72. | Phil Odonnell (G6) | SMUD- Ops | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 73. | Casey Sprouse (G6) | Sr. Term Marketer | | | | | | | | | | |
| 74. | Maria Denton (G6) | SRP | | | | | | | | | | |
| 75. | Terri M. Kuehneman (G6) | SRP System Operation | | | | | | | | | | |
| 76. | Raquel Agular (G6) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 77. | Ron Belval (G6) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 78. | Doug Bailey (G4) | TVA | ✓ | | ✓ | | ✓ | | | | | |
| 79. | Jim Haigh (G3) | WAPA | ✓ | | | | | ✓ | | | | |
| 80. | Raymond Vojdani (G6) | WAPA | | | | | | | | | ✓ | |
| 81. | Mike Wells (G6) | WECC | | | | | | | | | | ✓ |
| 82. | Neal Balu (G3) | WPS | | | ✓ | | ✓ | ✓ | | | | |
| 83. | Pam Oreschnick (G3) | XEL | ✓ | | ✓ | | ✓ | ✓ | | | | |

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group

G1 – APPA

G2 – ISO – RTO Standards Review Committee

G3 – MRO Members (MRO)

G4 – SERC Available Transfer Capability Working Group (SERC ATCWG)

G5 – PSC of South Carolina

G6 - WECC MIC MIS ATC Task Force

## Index to Questions, Comments, and Responses

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

**Summary Consideration:** Most stakeholders who responded to this question indicated that the applicability section of the standard needed revision. The drafting team has redrafted the standard based on a more in-depth reading of the functional model, and we believe it should address the majority of the concerns expressed by the industry. The applicability section of the standard was modified so that there are no requirements in the revised standard applied to the Reliability Coordinator or the Planning Coordinator – and the Transmission Operator was added as an applicable functional entity.

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | ☑ | "Planning Coordinator" is not a defined term. **Pleae** correct. |
| **Response:** We have drafted a definition to address this on an interim basis, until the Functional Model Drafting Team addresses it in more detail. According to members of the Functional Model Working Group, the terms 'Planning Authority' and 'Planning Coordinator' are equivalent. | | | |
| APPA | | ☑ | These requirements should be in the FAC series and developed by personnel who are experienced in the determination of flowgates and their limitations. The requirements, as written are requiring improper use of the values stated in the requirements. |
| **Response:** The drafting team drafted a Supplemental SAR and has expanded the membership of the drafting team to address this concern. | | | |
| BPA | | ☑ | "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority. |
| **Response:** We have drafted a definition to address this on an interim basis, until the Functional Model Drafting Team addresses it in more detail. According to members of the Functional Model Working Group, the terms 'Planning Authority' and 'Planning Coordinator' are equivalent. | | | |
| Entergy | | ☑ | R5 reference to Transmission Operator should be changed to Transmission Owner. |
| **Response:** We have included references to the transmission Owner with regard to Facility Ratings. (See R3 in the revised standard.) | | | |
| ITC | | ☑ | ITC agrees with the requirements, themselves, but disagrees with the responsible entities. The Transmission Owner and/or Transmission Operator should be responsible for determing all limits (thermal, voltage, stability) of the transmission facilities. The TO/TOP may choose to delegate the activities, but the requirements in this Standard have put the responsibility on the wrong entity. The RC should not be involved in the determination of facility limits unless so designated to do so. R4 and R5 are appropriate in that respect, but the others are not. As a Transmission Owner/Operator, ITC would be object to any rating greater than one we would provide. This is a dangerous possibility as currently written particularly if commericial interests could affect reliability considerations. |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** We have revised the standard so that it now requires the Transmission Operator to set TFC, but we have not specified how thermal, voltage, or stability limits are determined. The revised standard does indicate (R3) that the Facility Ratings in the transmission model used to determine AFC must include the Facility Ratings provided by Transmission Owners and Generator Owners. | | | |
| MEC Trading | | | The functional model doesn't necessarily translate to reality so this is hard to answer. |
| **Response:** The drafting team appreciates your comment, and has attempted to redraft the standard based on a more in-depth reading of the functional model. | | | |
| MEC | | ☑ | For R6, R8, R9, R10, R11 the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. Further R1 and R2 should also be revised for this reaons to also refer to the "Transmission Service Provider, the Reliabiltiy Coordinator and/or the Planning Coordinator, as appropriate." |
| **Response:** Most stakeholders who responded to this question and to similar questions for MOD-028 and MOD-029, indicated that the Transmission Operator should calculate TTC/TFC.<br>The drafting team deleted R6 from the revised standard. R6 required the Planning Coordinator ad Reliability Coordinator to provide the Transmission Service Provider with voltage and stability limits – the revised standard assigns the Transmission Operator responsibility for determining TFCs, and assumes that the Transmission Operator already has these limits.<br>R8, R9, and R10 are all related to the determination and dissemination of TFCs – these requirements had assigned to the Planning Coordinator and Reliability Coordinator and in the revised standard all are assigned to the Transmission Operator (see R2.3, R2.4 and R2.5 in the revised standard)<br>R11 required public posting of TFCs and this requirement has been deleted from the revised standard. All ATC-related posting requirements are being addressed by NAESB in business practices.<br>R1 was revised so that, instead of being assigned to the Planning Coordinator and Reliability Coordinator, R1 in the revised standard applies to the Transmission Service Provider to align with the revisions made to MOD-001 – Available Transfer Capability – where responsibility for the Available Transfer Capability Identification Document is assigned to the Transmission Service Provider. | | | |
| MRO | | ☑ | The MRO believes that for R6, R8, R9, R10, R11 the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. Further R1 and R2 should also be revised for this reaons to also refer to the "Transmission Service Provider, the Reliabiltiy Coordinator and/or the Planning Coordinator, as appropriate." |
| **Response:** Most stakeholders who responded to this question and to similar questions for MOD-028 and MOD-029, indicated that the Transmission Operator should calculate TTC/TFC. | | | |

| **Question #1** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| The drafting team deleted R6 from the revised standard. R6 required the Planning Coordinator ad Reliability Coordinator to provide the Transmission Service Provider with voltage and stability limits – the revised standard assigns the Transmission Operator responsibility for determining TFCs, and assumes that the Transmission Operator already has these limits.<br>R8, R9, and R10 are all related to the determination and dissemination of TFCs – these requirements had assigned to the Planning Coordinator and Reliability Coordinator and in the revised standard all are assigned to the Transmission Operator (see R2.3, R2.4 and R2.5 in the revised standard)<br>R11 required public posting of TFCs and this requirement has been deleted from the revised standard. All ATC-related posting requirements are being addressed by NAESB in business practices.<br>R1 was revised so that, instead of being assigned to the Planning Coordinator and Reliability Coordinator, R1 in the revised standard applies to the Transmission Service Provider to align with the revisions made to MOD-001 – Available Transfer Capability – where responsibility for the Available Transfer Capability Identification Document is assigned to the Transmission Service Provider. | | | |
| SERC ATCWG | | ☑ | See answer to #6. |
| **Response:** Please see the response to your comments on question 6. | | | |
| ERCOT | ☑ | | See IRC comments submitted by Charles Yeung. |
| **Response:** We did not receive IRC comments in response to this question. | | | |
| FirstEnergy | ☑ | | |
| IESO | ☑ | | |
| ISO SC | ☑ | | |
| Manitoba Hydro | ☑ | | |
| PSC SC | ☑ | | |

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

**Summary Consideration:** The drafting team has re-written the requirement describing how to determine ETC.

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | ☑ | The impact of load growth for Network Integration Transmission Service should be included in the second sub-bullet of R14.<br><br>The "five years or longer in duration" language should be removed from the fifth sub-bullet of R14. due to the fact that this element of Order 890 is only to be implemented by a TSP once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those exisitng Customers who have not yet been required to commit to five years of service to retain their roll-over rights. |
| **Response:** In response to this comment, the drafting team has written a more detailed description of how to determine ETC. R14 has been revised (now R6) to base the impact of Firm Network and native Load Service on peak load forecasts for the applicable periods, which would include load growth. The 'five years or longer in duration' was removed in support of your suggestion. (See R6.2 in the revised standard.) | | | |
| APPA | | ☑ | These requirements are tariff or contract requirements that will be contained in or a part of a regulatory or legal document. Some of these requirements are not a reliability issues since and should be removed. Those statements that want to know the effects of actions that are of a reliability nature will be determined by other functions not the TSP, which just sell transmission capacity. |
| **Response:** The requirement to calculate TFC was revised so that it applies to the Transmission Operator rather than the Transmission Service Provider. | | | |
| BPA | | ☑ | The impact of load growth for Network Integration Transmission Service should be included in the second sub-bullet of R14.<br><br>The "five years or longer in duration" language should be removed from the fifth sub-bullet of R14. due to the fact that this element of Order 890 is only to be implemented by a Transmission Service Provider (TSP) once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those existing Customers who have not yet been required to commit to five years of service to retain their roll-over rights. |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | The ninth sub-bullet should include all other impacts and not just the impacts using transmission service to service Native Load or firm Network Integration load. Therefore, "using transmission that serves Native Load or Firm Network Integration Transmission Service" should be deleted. |
| **Response:** In response to this comment, the drafting team has written a more detailed description of how to determine ETC. R14 has been revised (now R6) to base the impact of Firm Network and native Load Service on peak load forecasts for the applicable periods, which would include load growth.<br>The suggestion for deleting the phrase, 'using transmission that serves Native Load or Firm Network Integration Transmission Service' was adopted. In the revised standard the 'options' have been revised and restarted as elements that must be identified and included in the calculation for determining firm ETC. (See R6.1 in the revised standard)<br>The 'five years or longer in duration' was removed in support of your suggestion. (See R6.2 in the revised standard.) | | | |
| IESO<br>IRC | | ☑ | R14: It is not clear if the standard requires all inputs to be included in the calculation of the impact of Firm ETC. If so, 2 of bullet points are questionable:<br>• FIRM NITS Reservations (second bullet point) are only explicitly incorporated in ETC if they cross control area boundaries. (POR not equal to POD) Otherwise they are part of the base-flow calculations<br>- Designated Network Resources (DNRs) serving Native Load (first bullet point). In order to clarify, we could add to the second bullet: "not otherwise included in TRM or CBM or in the impacts of Native Load commitments"<br>• Impact of Ancillary Services not included already in TRM, is very difficult to quantify and include in ETC.<br>R18<br>• Non-Firm ETC calculations use the same base flow based on resources serving native load commitments as Firm ETC Calculations. Non-Firm NITS Reservations (second bullet point) are only explicitly incorporated in ETC if they cross control area boundaries (POR not equal to POD). Otherwise they are part of the base-flow calculations. |
| **Response:** In response to this comment, the drafting team has written a more detailed description of how to determine ETC. See R6 and R7 in the revised standard. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See the response to IRC's comments. | | | |
| ITC | | ☑ | It is not clear that any "allocations" of flowgate capacity, such as in the MISO/PJM Seams agreement, are covered here. These allocations, while technically covered by the 2nd to last bullet, need to be addressed by stronger language than a blanket "any other agreements" clause. |
| **Response:** The reliability standard refers only to the allocation of TTC from an ownership standpoint. It does not address contractual allocations of ATC. | | | |
| MEC | | ☑ | 1. R1.1, R3, R11and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | information is not made publicly without registration.<br><br>2. R14 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropriate level of " the following inputs.<br><br>3. R16 the impacts by more than 3% are consistent with post-contingent flowgates. It should be noted that there are continuing to exist in the area, pre-contingent flowgates which would be inproperly represented by post-contingent flowgates. The pre-contingent flowgates in the area generally only consider signficant third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent.<br><br>4. R18 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the area to maximize the non-firm offerings in the operating horizon. I suggest wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC."<br><br>5. Either use existing transmission commitments in lower case or else provide a definition for the NERC Glossary. |
| **Response:** 1. The team has removed all requirements that included make data or information, publicly available', as NAESB will address all the posting requirements.<br>2. The term "an appropriate level of" may not allow for an accurate measurement of compliance. We have redrafted this language significantly, which may address your concerns.<br>3. The group has elected to use a 3% threshold, based on the work of the Alliant West TLR Task Force.<br>4. The standard allows for, but does not require, the use of meter data in the components used to determine ETC.<br>5. We have provided a definition of ETC, and each standard (MOD-028, MOD-029, MOD-030) explains the calculation of ETC. | | | |
| MRO | | ☑ | 1. R1.1, R3, R11and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration.<br>2. R14 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropraite level of " the following inputs.<br>3. R16 the impacts by more than 3% are consistent with post-contingent flowgates. It should be noted that there are continuing to exist in the MRO area, pre-contingent flowgates which would be inproperly represented by post-contingent flowgates. The pre-contingent flowgates in the MRO generally only |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | consider signficant third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent.<br>4. R18 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the MRO to maximize the non-firm offerings in the operating horizon. The MRO suggests wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC."<br>5. Either use existing transmission commitments in lower case or else provide a definition for the NERC Glossary. |
| **Response:** 1. The team has removed all requirements that included make data or information, publicly available', as NAESB will address all the posting requirements.<br>2. The term "an appropriate level of" may not allow for an accurate measurement of compliance. We have redrafted this language significantly, which may address your concerns.<br>3. The group has elected to use a 3% threshold, based on the work of the Alliant West TLR Task Force.<br>4. The standard allows for, but does not require, the use of meter data in the components used to determine ETC.<br>5. We have provided a definition of ETC, and each standard (MOD-028, MOD-029, MOD-030) explains the calculation of ETC. | | | |
| Entergy | ☑ | | Sub requirements shown as bullets should be changed to numbered subrequirements in R14, R16 and R18. |
| **Response:** Agree. Where a sub-bullet indicated a 'required' performance, the bullet was changed to a numbered item in the revised standard. | | | |
| FirstEnergy | ☑ | | However, the term "Post-backs" is industry jargon and should be replaced with the term "reinstatement" to add clarity. |
| **Response:** We have continued to use the term "post-backs," but have requested that NAESB write its definition. | | | |
| MEC Trading | ☑ | | |
| Manitoba Hydro | ☑ | | |
| PSC SC | ☑ | | |
| SERC ATCWG | ☑ | | |

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

**Summary Consideration:** There was no consensus amongst the stakeholders who responded to this question. The drafting team has rewritten the requirement describing the conversion to be clearer and provide more detail.
The changes made include the addition of the following algorithm:

$$TC = \min\{PTC_1, PTC_2, \ldots PTC_n\} \text{ And } PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either 'Available' or 'Total').

**P** is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or PTDF Flowgate.

**$PTC_n$** is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n*.

**$FC_n$** is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

**$DF_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | Need to let the expanded SDT review this by personnel knowledgeable in development of AFT and distribution factors |
| **Response:** The SDT was expanded and the revised standard reflects the requested actions. | | | |
| Entergy | | ☑ | The requirement should be worded in simple language to reflect how AFCs are determined rather than an equation that a program can use in developing program. |
| **Response:** We have expanded the details in the standard to better explain the process. Most comments wanted more specific details, and the most effective way of providing those details was in an algorithm. The revised standard includes the algorithm and defines each of the elements in the algorithm – while this doesn't support your specific request, the additional specificity should support the intent of your request. | | | |
| ITC | | ☑ | The conversion of AFC to ATC is covered, but it is not clear. The original SAR for this standard included a white paper with appropriate coversion formulae. Please consult and include the translation equations. |
| **Response:** We replaced the requirement with a more detailed algorithm that includes a definition of each of the elements | | | |

| **Question #3** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| in the algorithm. | | | |
| MEC | | ☑ | The R22 is inadequate in describing what must be done. It is unclear what path the flowgates are to be converted to. Are the flowgate quantities to be converted into equivalent control area to control area path quantities? Are the flowgate quantities to be converted into flowgate path quantities? If it is the latter, what are the definitions and purposes of the flowgate path quantities? In addition, I do not understand what the benefits are in converting Flowgate AFCs to path AFCs. It seems to be an unnecessary and confusing requirement albeit one in FERC Order 890. |
| **Response:** We replaced the requirement with a more detailed algorithm that includes a definition of each of the elements in the algorithm. Generally transmission service is sold on a path basis, with the limit being the most limiting Flowgate above the threshold limit. | | | |
| Manitoba Hydro | | ☑ | I don't believe there should be a conversion it only leads to uncertainty. I believe that the committee should be able to standardize on one technique. |
| **Response:** Order 890 allows for three methodologies, and the conversion explains how to post the results of one methodology in the terms used by the other two. | | | |
| MRO | | ☑ | The MRO believes that the R22 is inadequate in describing what must be done. It is unclear what path the flowgates are to be converted to. Are the flowgate quantities to be converted into equivalent control area to control area path quantities? Are the flowgate quantities to be converted into flowgate path quantities? If it is the latter, what are the definitions and purposes of the flowgate path quantities? In addition, the MRO does not understand what the benefits are in converting Flowgate AFCs to path AFCs. It seems to be an unnecessary and confusing requirement albeit one in FERC Order 890. |
| **Response:** We replaced the requirement with a more detailed algorithm that includes a definition of each of the elements in the algorithm. Generally transmission service is sold on a path basis, with the limit being the most limiting Flowgate above the threshold limit. | | | |
| SERC ATCWG | | ☑ | The definition provided in the SAR was clearer than the current definition. The new definition introduces new terms into the process that are not industry standard or recognizable. |
| **Response:** We replaced the requirement with a more detailed algorithm that includes a definition of each of the elements in the algorithm. We believe all terms are either in the NERC Glossary or are proposed by the updated MOD Standards. | | | |
| ERCOT | ☑ | | See IRC comments submitted by Charles Yeung. |
| **Response:** See the response to IRC's comments | | | |
| BPA | ☑ | | However, for the reasons explained in our response to the MOD-030-1 Comment Form's question 4, BPA suggests that R22. be modified to the following:<br>" The Transmission Service Provider shall make publicly available a mechanism for interested parties to convert Flowgate AFCs to path ATCs based on…" |
| **Response:** FERC has directed that path ATCs be posted. NAESB will be addressing what needs to be posted and how. | | | |
| IESO | ☑ | | Yes, the conversion is described adequately. In the first bullet point, "…the Transmission Service |

| **Question #3** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Provider shall calculate the partial AFC of that…" should be written as "…the Transmission Service Provider shall calculate the partial ATC of that…" |
| **Response:** The drafting team appreciates your response. You are correct, 'partial AFC should have been partial ATC.' | | | |
| IRC | ☑ | | Yes, conversion described adequate.<br>• Partial AFC should be partial ATC in first bullet point. |
| **Response:** The drafting team appreciates your response. You are correct, 'partial AFC should have been partial ATC.' | | | |
| MEC Trading | ☑ | | |
| PSC SC | ☑ | | |
| FirstEnergy | ☑ | | |

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

**Summary Consideration:** Most stakeholders who responded to this question indicated that there would be problems in complying with the originally proposed R21 and R24. The drafting team has removed the posting requirements from the standard. NAESB will be addressing what needs to be posted and how in business practices.

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Entergy | | ☑ | AFCs are not required to be posted as these do not mean much to the users, therefore, R21 should be deleted. |
| **Response:** R21 was deleted from the revised standard. NAESB will be making the determination if these need to be posted or not. | | | |
| PSC SC | | ☑ | |
| WECC MIC MIS ATC TF | ☑ | | (The below statement is proposed by BPA. Is the WECC Team OK with supporting it?) Under the flowgate methodology, ATC is a value derived from an analysis of the expected powerflow impacts of a reservation across multiple flowgates. Consequently, it is the posting of AFC and timely posting of changes to AFC that inform whether transfer capability exists to support a request for transmission service. ATC for a POR-POD path is derived from posted AFC. When posting both ATC by path as well as AFC by flowgate, there is a risk that the AFC and ATC values could get "out of sync" due to automation lag-time, etc. BPA believes that greater consistency and transparency is achieved if only AFC values are posted for each flowgate, and requestors are provided with a "conversion calculator" that calculates ATC for their requested path based on posted AFC's. |
| **Response:** FERC has directed that path ATCs be posted. NAESB will be addressing what needs to be posted and how. | | | |
| APPA | ☑ | | This Standard trys to provide detail requirements for AFT, ATC, ETC and the requirements of 3 different functional entities and it is written in a manner that will not support a Compliance program. |
| **Response:** We have redrafted the standards to address this concern. The applicability of the standard was revised and the Planning Coordinator and Reliability Coordinator are not assigned responsibility for any requirements. | | | |
| BPA | ☑ | | Under the flowgate methodology, ATC is a value derived from an analysis of the expected powerflow impacts of a reservation across multiple flowgates. Consequently, it is the posting of AFC and timely posting of changes to AFC that inform whether transfer capability exists to support a request for transmission service. ATC for a POR-POD path is derived from posted AFC. When posting both ATC by path as well as AFC by Flowgate, there is a risk that the AFC and ATC values could get "out of sync" due to automation lag-time, etc. BPA believes that greater consistency and transparency is achieved if only AFC values are posted for each Flowgate, and requestors are provided with a "conversion calculator" that calculates ATC for their requested path based on posted AFC's. |
| **Response:** FERC has directed that path ATCs be posted. NAESB will be addressing what needs to be posted and how. | | | |
| ERCOT | ☑ | | See comment 9. |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** | | | |
| FirstEnergy | ☑ | | The standard should include specifics of methods for complying with the term "publicly available" such as posting on OASIS, a corporate web page, etc. (This concept is mentioned in all MOD-028, MOD-029, and MOD-030.) |
| **Response:** The SDT has eliminated this language, and will let NAESB specify the manner in which information is to be posted. | | | |
| IESO<br>IRC | ☑ | | R21 and R24<br>Current tools allow the submission of requests and retrieval of available and calculated AFC and ATC data. It is questionable if that is considered being compliant with R21 and R24. If not, changes to the software might be required to meet the requirements of R21 and R24. |
| **Response:** R21 and R24 have been deleted from the revised standard as they were requirements to make information publicly available and NAESB is addressing these requirements in its business practices. | | | |
| ITC | ☑ | | A ridiculous amount of paper or web space will be used if all ATC path values are posted for large footprints. Flowgates can be in the thousands but ATC paths are quadratic functions of the number of Sources/Sinks (i.e., too many paths to print). ATC for a given path should be on request. (i.e., ask for the path and the TSP provides that specific path ATC via OASIS). This should be either through manual entry by the requestor or electronically via a requestor electronic query tool (i.e., computer program query). |
| **Response:** FERC has directed that path ATCs be posted. R21 and R24 have been deleted from the revised standard. NAESB will be addressing what needs to be posted and how. | | | |
| MEC | ☑ | | It will be incredibly confusing posting both AFCs and ATCs for the same transmission service. I agree that this is in accordance with the FERC Order 890; however, I do not understand what the benefits of this conversion to open transmission service and reliability. I ask the SDT to clarify. |
| **Response:** R21 and R24 have been deleted from the revised standard. NAESB will be addressing what needs to be posted and how. | | | |
| MRO | ☑ | | It will be incredibly confusing posting both AFCs and ATCs for the same transmission service. The MRO agrees that this is in accordance with the FERC Order 890; however, the MRO does not understand what the benefits of this conversion to open transmission service and reliability. The MRO asks the SDT to clarify. |
| **Response:** R21 and R24 have been deleted from the revised standard. NAESB will be addressing what needs to be posted and how. | | | |
| SERC ATCWG | ☑ | | Posting the AFC numbers provide no additional value if the ATC numbers are posted. |
| **Response:** R21 and R24 have been deleted from the revised standard. NAESB will be addressing what needs to be posted and how. | | | |

5. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

**Summary Consideration:** The drafting team disagreed with the suggestions regarding FAC-012. Other comments suggested a general concern with a lack of clarity and detail regarding the Order, which is beyond the scope of the drafting teams work.

| **Question #5** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings. FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC. |
| **Response:** We agree the FERC order requires this; however, we believe we have good technical reasons for writing the standard otherwise. | | | |
| Duke | | ☑ | Conditional Firm Service (CFS) and Planning Redispatch Service (PRS) under Order No. 890 create new issues relating to modeling and calculating ATC. Specifically, when PRS is offered to maintain service, modeling for ATC calculations will be impacted during these periods. TTC must be modeled/calculated accounting for the new CFS/PRS requirements. |
| **Response:** Since these concepts have not been fully developed, the standard as drafted allows for the inclusion of CFS and PRS when modeling usage of the system. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| IESO | | ☑ | Note - We don't have a complete overview of all directives to answer this question. |
| **Response:** The drafting team will post a table that includes all relevant directives from FERC Order 693 and 890 to show the standard and requirement that addresses each directive. | | | |
| IRC | | ☑ | Note - Don't have a complete overview of all directives to answer that question. This is time intensive!!!! |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** The drafting team will post a table that includes all relevant directives from FERC Order 693 and 890 to show the standard and requirement that addresses each directive. | | | |
| MEC Trading | | ☑ | Standard is a fill-in-the-blank |
| **Response:** The SDT has added significant detail to address this concern. | | | |
| FirstEnergy | ☑ | | |
| Entergy | ☑ | | |
| MEC | ☑ | | |
| MRO | ☑ | | |
| PSC SC | ☑ | | |

6. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

**Summary Consideration**: Most stakeholders who responded to this question indicated that they disagreed with the applicability section of the standard. The SDT made changes to the functional entities based on commenters' suggestions, and the revised standard does not include either the Planning Coordinator or the Reliability Coordinator as responsible entities – and the Transmission Operator has been added as a responsible entity**.**

The drafting team modified MOD-001 — Available Transfer Capability to assign the Transmission Service Provider with the responsibility for having an Available Transfer Capability Implementation Document – and modified all the standards in this set (MOD-028, MOD-029, MOD-030) to clarify that the Transmission Operator and Transmission Service Provider are the entities with responsibility for developing the calculations used to determine ATC. The Transmission Operator determines the Transfer Capabilities and the Transmission Service Provider determines ATC.

| **Question #6** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | | See above on defining Planning Coordinator. |
| **Response:** We have removed the PC from the standard. | | | |
| BPA | | ☑ | "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority. |
| **Response:** We have removed the PC from the standard. | | | |
| IESO | | ☑ | TSP is the sole entity responsible for performing calculations, and posting of the results. The PC, RC, and TO only submit data to the TSP, such as list of OTDF and PTDF flow gates, seasonal limits of flow gates, flowgate components, flow directions on flowgate components etc. They do not calculate ATC, hence R1 is irrelevant. |
| **Response:** The drafting team modified MOD-001 — Available Transfer Capability to assign the Transmission Service Provider with the responsibility for having an Available Transfer Capability Implementation Document (ATCID)– and modified all the standards in this set to clarify that the Transmission Operator and Transmission Service Provider are the entities with responsibility for developing the calculations used to determine ATC. The Transmission Operator determines the Transfer Capabilities and the Transmission Service Provider determines ATC.<br>R1 addresses the ATCID and in the revised standard is assigned to the Transmission Service Provider.<br>Note that all posting requirements have been removed from the revised standards. | | | |
| IRC | | ☑ | TSP is responsible to perform calculations, and post the results, the PC and RC and TO only submit data to TSP, such as list of flow gates, limits of flow gates. They do not calculate ATC, hence R1 is irrelevant. |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** The drafting team modified MOD-001 — Available Transfer Capability to assign the Transmission Service Provider with the responsibility for having an Available Transfer Capability Implementation Document (ATCID)– and modified all the standards in this set (MOD-028, MOD-029, MOD-030)to clarify that the Transmission Operator and Transmission Service Provider are the entities with responsibility for developing the calculations used to determine ATC. The Transmission Operator determines the Transfer Capabilities and the Transmission Service Provider determines ATC.<br>R1 addresses the ATCID and in the revised standard is assigned to the Transmission Service Provider.<br>Note that all posting requirements have been removed from the revised standards. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| ITC | | ☑ | Applicable Entity 4.2 is not appropriate. Reliability Coordinators should not be calculating ATC. According to the Functional Model, ATC Calculations are performed by the Transmission Service Provider (Task #2, "Determine and post available transfer capability values.") R4 and R5 identify the TO and TP as responsible entities, and need to be included in the applicability sections. |
| **Response:** The drafting team modified MOD-001 — Available Transfer Capability to assign the Transmission Service Provider with the responsibility for having an Available Transfer Capability Implementation Document (ATCID)– and modified all the standards in this set (MOD-028, MOD-029, MOD-030) to clarify that the Transmission Operator and Transmission Service Provider are the entities with responsibility for developing the calculations used to determine ATC. The Transmission Operator determines the Transfer Capabilities and the Transmission Service Provider determines ATC. We do not agree that the Transmission Planner is applicable. R4 was deleted from the revised standard as the Transmission Operator will already have these limits – and R5 was merged with other requirements into R2 which is assigned to the Transmission Operator (see 42.3 in the revised standard.) | | | |
| MEC | | ☑ | It is not appropriate to qualify the Functional Entity as provided in A.4.1 through A.4.3, that is, A.4.1 through A.4.3 should just list the NERC functions from the NERC functional model and not qualify it. For example, 4.1 should be "Planning Coordinator" not "Each Planning Coordinator that uses the Flowgate Network Response method to calculate…..". Then it is up to Planning Coordinators etc. to review the standard to see how the requirements are to be applied, if at all. |
| **Response:** The NERC Standards Development Process encourages the qualification of applicable entities to ensure only the appropriate entities are required to adhere to the standard. | | | |
| MRO | | ☑ | The MRO believes it is not appropriate to qualify the Functional Entity as provided in A.4.1 through A.4.3, that is, the MRO recommends that A.4.1 through A.4.3 just list the NERC functions from the NERC functional model and not qualify it. For example, 4.1 should be "Planning Coordinator" not "Each Planning Coordinator that uses the Flowgate Network Response method to calculate…..". Then it is up to Planning Coordinators etc. to review the standard to see how the requirements are to be applied, if at all. |
| **Response:** The NERC Standards Development Process encourages the qualification of applicable entities to ensure only the appropriate entities are required to adhere to the standard. | | | |

| **Question #6** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| SERC ATCWG | | ☑ | The applicability section needs clarification. Referencing R1,6,8,9 and 10 they should apply only to those entities performing the function. The standard should not require the calculations be made by the PC and RC, but should be applicable to the designated entitiy performing these calculations . The designated entity must be specified as a requirement in this standard. For example: The TSP, PC and RC must specify and agree to the entity that performs this function in the TSP's ATCID as required in MOD 1. The current revision of MOD-001 states the following requirement as R1: "Each Transmission Service Provider, and its associated Planning Coordinators and Reliability Coordinators, shall agree upon and implement one or more of the ATC methodologies specified in Reliability Standard MOD-028, MOD-029, and MOD-030 for use in determining Transfer Capabilities of those Facilities under the tariff administration of that Transmission Service Provider." The requirements of MOD-0028 should refer to the Designated Entity specified through this requirement. The following are examples of how this would be implemented in the standard:<br><br>B. Requirements<br>R4. Each Designated Entity shall ensure that the Total Transfer Capability (TTC) for each of its Transmission Service Provider's POR to POD Paths is calculated and up-to-date for use within the Transfer Capability time horizons specified in MOD-001 R2.<br>R5. Prior to calculating TTC, each Designated Entity shall update the following components of the base case power flow model it uses to calculate TTC for the time horizon being studied: |
| **Response:** We have changed the functional entities referenced to address your concerns.<br>R1 was revised so that, instead of being assigned to the Planning Coordinator and Reliability Coordinator, R1 in the revised standard applies to the Transmission Service Provider to align with the revisions made to MOD-001 – Available Transfer Capability – where responsibility for the Available Transfer Capability Identification Document is assigned to the Transmission Service Provider. Note that MOD-001 was also revised to clarify that the Transmission Service Provider calculates ATC.<br>The drafting team deleted R6 from the revised standard. R6 required the Planning Coordinator ad Reliability Coordinator to provide the Transmission Service Provider with voltage and stability limits – the revised standard assigns the Transmission Operator responsibility for determining TFCs, and assumes that the Transmission Operator already has these limits.<br>R8, R9, and R10 are all related to the determination and dissemination of TFCs – these requirements had assigned to the Planning Coordinator and Reliability Coordinator and in the revised standard all are assigned to the Transmission Operator (see R2.3, R2.4 and R2.5 in the revised standard)<br><br>"Designated Entity" is inappropriate for a responsible entity. The Functional Entity may delegate tasks, but the Functional Entity remains the responsible entity. | | | |

7. In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

**Summary Consideration:** There was no consensus amongst the stakeholders who responded to this question. The DT discussed this issue in an attempt to define specific requirements to ensure consistent implementation. Several different approaches were discussed; however, talking through examples it was determined that each implementation would have a detrimental impact on either reliability or Open Access. Therefore this requirement was removed. This shall serve as a single response to opinions offered in response to this question.

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| IRC | | ☑ | No R15 doesn't meet the intend of paragraph 245. Most of the PtP Reservations don't have specific resources as Source, they typically source from a group of commonly dispatched units. Also most Tariff's allow re-direct of Reservations to different Sources, so excluding Reservations from impact calculations could possibly result in overselling the system if the excluded reservation is re-directed to a different source. It might be possible to make some general guidelines to address the paragraph 245 of Order 890 such as:<br>• Total sum of Reservations (Confirmed, Approved, Study) impacting a specific corridor, such as a DC tie should not exceed the total capacity of the corridor.<br>• Total sum of Reservations (Confirmed, Approved, Study) sinking in a Control Area should not exceed the total Load of the Control Area.<br>• Total sum of Reservations ((Confirmed, Approved, Study) sourcing from a group of commonly dispatched units should not exceed the total available generation capacity of that group of units. |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| ITC | | ☑ | It meets the intent but is subject to potentiallt adverse interpretation. It is true that a POR may not exceed Pmax for the installed generation; however, when multiple requests are received for the POR that exceed Pmax, should the requests be taken first-come-first-served until Pmax is reached? Should the worst-case scenario be studied and used to set limits? Should the requests be pro-rated until the sum of the requests is reduced to Pmax? We believe the TSP should be allowed some leeway in how they model these situations, in order to prevent reliability problems. |
| IESO | | ☑ | No. R15 doesn't meet the intend of paragraph 245. Most of the PtP Reservations don't have specific resources as Source, they typically source from a group of commonly dispatched units. Also most Tariff's allow re-direct of Reservations to different Sources, so excluding Reservations from impact calculations could possibly result in overselling the system if the excluded reservation is re-directed to a different source. It might be possible to make some general guidelines to address the paragraph 245 of Order 890 such as: |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | • Total sum of Reservations (Confirmed, Approved, Study) impacting a specific corridor, such as a DC tie should not exceed the total capacity of the corridor.<br>• Total sum of Reservations (Confirmed, Approved, Study) sinking in a Control Area should not exceed the total Load of the Control Area.<br>• Total sum of Reservations ((Confirmed, Approved, Study) sourcing from a group of commonly dispatched units should not exceed the total available generation capacity of that group of units. |
| MEC | ☑ | ☑ | The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests to the source point where subsequent requests will result in power being moved away from the point and show how the Transmission Service Provider than reviews the impacts to meet the requirement. |
| MRO | ☑ | ☑ | The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests to the source point where subsequent requests will result in power being moved away from the point and show how the Transmission Service Provider than reviews the impacts to meet the requirement. |
| FirstEnergy | ☑ | | MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once, eliminate duplication, and simplify the applicability sections of MOD-028, 029, and 030 |
| **Response:** It was the decision of the SDT, supported by stakeholder comments, that MOD-001 be an overview, while MOD-028,-029-030 are separated to address various methods of calculation of TTC/ATC/AFC. The Order allows for more than one method; the SDT believe this approach is more clear and transparent to the industry. | | | |

| **Question #7** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| FirstEnergy | ☑ | | However, the phrase "not exceed" can be replaced with the word "the" since the term "limiting the total impact" is synonomous. |
| MEC Trading | ☑ | | The words meet the intent of the order, but the order may not be technically correct, nor consistent with other OATT requirements. |
| Entergy | ☑ | | |
| Manitoba Hydro | ☑ | | |
| PSC SC | ☑ | | |
| WECC MIC MIS ATC TF | ☑ | | |
| Entergy | ☑ | | |
| PSC SC | ☑ | | |

8. Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

**Summary Consideration:** The drafting team only received one suggestion for a different threshold (5%); and elected to retain the 3% threshold. The 3% is consistent with the work of the Alliant West TLR Task Force, which performed statistical analyses to determine a more efficient threshold for identifying impacting transactions.

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF<br>BPA | | ☑ | The threshold of 3% appears to be an arbitrary level. This level may be rooted in Operational and Planning studies that consider impacts from outages on one TP's system that increase loading on an element of another TP's system by 3% or more. While this level may be a good indicator of impact, it may not provide an indicator of which party's ownership or allocation of facilities is being used. It does not assure TPs will be able to preserve their rights (i.e. by contractual allocation) with a fixed threshold of 3%. |
| **Response:** The 3% is consistent with the work of the Alliant West TLR Task Force, which performed statistical analyses to determine a more efficient threshold for identifying impacting transactions. | | | |
| Entergy | | ☑ | The threshold level of 3% for third party should not be included in this standard since there is no such threshold level for Transmission Service Provider's own data. |
| **Response:** We have modified the standard to clarify that providers may use a lower threshold if they wish – see the footnotes added to R7 in the revised standard. | | | |
| IESO<br>IRC | | ☑ | We assume the third party is a 1 tier or 2 tier Control Area adjacent to the Tariff footprint of the TSP. Some questions:<br>• Paragraph talks about impact transmission capability with 3%. Does this mean impact any flow gate within the Tariff footprint of the TSP with 3%. What about flow gates that are tie lines between Tariff footprint and 1tier and limiting element is in 1tier.<br>• What participation factors and generators should be used to determine if the GLDF of commonly dispatched units of 1tier Control Area is >3%. NERC IDC?<br>• Is the data listed in bullet point 2,3,4,5,6 of R16 going to be submitted by neighbor TSP. If so it is sufficient to specify that a TSP is getting the list of Reservations as specified in 2,3,4,5,6 of R16 from a neighboring TSP without having to know detail as specified in the bullet points. |
| **Response:** 1.) We have modified the standard such that the 3% applies to only 1st tier TSPs and those TSPS with which coordination agreements have been executed. We have also defined the criteria for how to select flowgates.<br>2.) The distribution factors should be based on calculating TSP's methodology for determining distribution factors.<br>3.) You will need to filter the data, since the data provided may include information relevant to one party but not another. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See IRC response. | | | |
| MEC Trading | | ☑ | If is this appropriate for MOD-30, it is appropriate for MOD-28. Why do you specifically spell out a |

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | requirement for MOD-30 but not MOD-28? |
| **Response:** The methodologies are different, and different approaches apply. We will look at making them more consistent in future versions. We have added a requirement to MOD-028 to consider third-party reservations. | | | |
| MEC | | ☑ | The impacts by more than 3% are consistent with post-contingent flowgates. It should be noted that pre-contingent flowgates are continuing to exist in the area. Such pre-contingent flowgates have physical conditions that would be improperly represented by post-contingent flowgates so the pre-contingent flowgates must remain in place. The pre-contingent flowgates in the area generally only consider significant those third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent. |
| **Response:** The 3% is consistent with the work of the Alliant West TLR Task Force, which performed statistical analyses to determine a more efficient threshold for identifying impacting transactions. | | | |
| MRO | | ☑ | The impacts by more than 3% are consistent with post-contingent flowgates. It should be noted that pre-contingent flowgates are continuing to exist in the MRO area. Such pre-contingent flowgates have physical conditions that would be improperly represented by post-contingent flowgates so the pre-contingent flowgates must remain in place. The pre-contingent flowgates in the MRO generally only consider significant those third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent. |
| **Response:** The 3% is consistent with the work of the Alliant West TLR Task Force, which performed statistical analyses to determine a more efficient threshold for identifying impacting transactions. | | | |
| Manitoba Hydro | | ☑ | During a TLR or redispatch, a 3% cutoff would require the third party to adjust their resources by up to 33 MW for every 1MW of relief. I believe that this is too much. I would recommend third party mitigation has to be a balance of impact and ability for relief and those 3% biases that balance. I would recommend that the 5% impact which still requires a potential 20 MW adjustment for every 1 MW of relief maintains the balance between impact and ability for relief. |
| **Response:** This requirement addresses what transactions that are included in TSP analyses, and is not directly related to curtailments. | | | |
| ITC | ☑ | | This is overdue in our estimation. Using 5%, as some have done, has resulted in unnecessary TLRs, particularly on lower voltage (138kV and below) systems. |
| **Response:** Thank you for your support. | | | |
| FirstEnergy | ☑ | | |
| PSC SC | ☑ | | |

9. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please describe the conflict in the comments area.

**Summary Consideration:** Most stakeholders who responded to this comment indicated they were not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement. The SDT suggests that ERCOT, and others who believe this standard should not apply to them, pursue a regional difference to address their concerns.

| **Question #9** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| ITC | | ☑ | There are 3 methods, pick the one that works. We have noted in our other comments that some entities, such as New England, have approved tariffs that don't require the sale of transmission service. They should not have to pick any method but should, as we have noted, be required to provide data to neighboring TSPs that do sell transmission service. |
| **Response:** The SDT agrees this is a concern – entities with this concern need to submit a request for a Regional Difference. | | | |
| FirstEnergy | | ☑ | |
| WECC MIC MIS ATC TF | | ☑ | |
| Entergy | | ☑ | |
| MEC | | ☑ | |
| Manitoba Hydro | | ☑ | |
| MRO | | ☑ | |
| PSC SC | | ☑ | |
| ERCOT | ☑ | | ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area and there has been no reservation of transmission capacity in ERCOT.<br><br>Available Transfer Capability is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. |

| **Question #9** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. The ERCOT Interconnection has already moved "beyond" ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therfore both ERCOT and SPP are notified when the DC Tie capability is reduced.<br><br>Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.<br><br>In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.<br><br>In the current and future ERCOT market design the method of calculating ATC, TTC and the use of CBM and TRM are not applicable to the ERCOT Region. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Control Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance. |
| **Response:** The SDT agrees this is a concern – ERCOT needs to submit a request for a Regional Difference. | | | |

| Question #9 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| MEC Trading | ☑ | | This standard is not requiring consistenecy per the requirement of FERC Order 890. |
| **Response:** Please see the revised set of standards. The drafting team modified all of the standards to require greater consistency between standards. | | | |

10. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

**Summary Consideration:** The SDT made changes in response to some of the comments below, including adding definitions and redrafting sections to be clearer. Note that NAESB will be addressing some of the more commercial areas of the subject matter, such as timing guidelines and posting requirements.

| **Question #10** | |
|---|---|
| **Commenter** | **Comment** |
| WECC MIC MIS ATC TF | A. R1.2 should be modified due to the fact that Facilities don't cause congestion, rather they experience congestion. The following change to the language would be more accurate:<br>"How the methodology identifies transmisison Facilities that are expected by the AFC calculator to experience congestion on the transmission system."<br>B. See comments on MOD-29.<br>In the "Applicability" section, the term "Available Transfer Capability Implementation Document" is used as a defined term. The term is used in MOD-01 R3. At minimum the ATCID either needs to be defined or a reference to the MOD-01 must be inserted for cross reference.<br>C. R.1 through R.3. appear to be a prohibited "fill-in-the-blank."<br>D. R22. Typo. Change "covert" to "convert." |
| **Response:** A. We have redrafted this language, and it is now included in R2.1. (See R2.1.3 in the revised standard.)<br>B. We have defined ATCID.<br>C. We have attempted to address this comment by requiring more detail and making explicit requirements where possible.<br>D. We have corrected this error (See R10 in the revised standard). | |
| BPA | The ATC MOD's (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide descriptions of these methodologies.<br>The Applicability section 4.1. through 4.3. Should have the phrase "Available Transfer Capabilities for paths" replaced with "Available Flowgates Capabilities for Flowgates".<br>R1.2. should be modified due to the fact that Facilities don't cause congestion, rather they experience congestion. The following change to the language would be more accurate:<br>"How the methodology identifies transmisison Facilities that are expected by the AFC calculator to experience congestion on the transmission system."<br>R3. A Flowgate should not be defined as a thermal, voltage, or stability type due to the fact that Flowgates are limited by thermal, voltage, or stability problems that can vary depending on system conditions.<br>R4. through R8. should be combined into two requirements:<br>1) Each entity generating Flowgate limit values (note that it's not clear if this should be the Transmission |

| **Question #10** | |
|---|---|
| **Commenter** | **Comment** |
| | Owner, Transmission Planner, Planning Coordinator, and/or Reliability Coordinator) shall provide current Flowgate limit data to Transmission Service Providers (TSPs); and<br>2) TSPs shall use the lesser of the thermal, voltage, or stability limits that apply to the current system conditions.<br>R18.-sub-bullet 5, R23., and R24. should each have the "ATC"s replaced with "AFC"s, for the reasons explained in our response to the MOD-030-1 Comment Form's question 4.<br>R24. should have "path" replaced with "Flowgate", for the reasons explained in our response to the MOD-030-1 Comment Form's question 4. |
| **Response:** The SDT has included definitions of the methodologies for the glossary.<br>Regarding 4.1 through 4.5, we have modified the standard to use the phrase, 'for Posted Paths' and included a definition of 'Posted Path'.<br>R1.2 has been redrafted, and it is now included in R2.1 (See R2.1.3 in the revised standard.)<br>R3: We have changed the language in R3 to address this comment, and moved the language to 2.3.<br>Regarding R3 through R5, we have replaced this language with R2.3 and 2.5.<br>Regarding R24 Was deleted and is being addressed by NAESB along with the other requirements aimed at 'posting'. | |
| Duke | R1.1 does not create the same level of transmission service as created in MOD-028. MOD 028 R6.1 involves N-1 transmission contingency AND ramping/partial contingency of generation. MOD-030 R1.1 appears to only require N-1 transmission or generation contingency. This is not comparable service.<br>For R3. need to also include why the Flowgate is a limit |
| **Response:** MOD-028 as currently written allows for load adjustments instead of generation adjustments. Regarding R3, this will be addressed by NAESB, as will all other public posting requirements. | |
| ITC | We think this is a much better standard than MOD-028 and -029. It should provide for greater flexibility and reliability. We think all methods should be examined closely if there is any evidence of overselling (as evidenced byTLRs and market congestion) or underselling (as evidenced by denial of service without TLRs or market congestion). |
| **Response:** Thank you for your support. | |
| MEC Trading | This MOD should be combined with MOD-28 and everyone using a distribution factor based analysis should use the same methodology and the amount of consistency should be increased significantly. |
| **Response:** Most stakeholders supported the division of the various ATC calculation methods into separate standards. The SDT believes the differences between the two approaches merit two different standards | |
| MEC | 1. R1.1 implies that the only planning criteria that should be used in ATC calculations is Category B in Table 1 of the NERC Standards. That is incorrect, the methodology should describe how it meets the planning criteria that is appropriate for posted values including applicable NERC Standards, regional criteria, Transmission Owner criteria, etc. Therefore, R1.1 should state that "How methodology meets the planning criteria in NERC Standards, regional standards, Transmission Owner's planning criteria, Transmission Planner's planning criteria, and other applicable |

| **Question #10** | |
|---|---|
| **Commenter** | **Comment** |
| | planning criteria used by the Transmission Planner to plan the system.<br>2. R8 does not cover all the limitations that are possible for flowgates, for example, the limitation may be due to high transfers causing low voltage on the system after the next condition. This is not an example of a thermal rating or a voltage limit of the power transfer. I suggest that an additional bullet be added to R8 stating "Any other constraint to power transferred across the Flowgate, if applicable. For such constraints, the constraint should be defined, explained, and examples given in the methodology so as to ensure that the ATC methodology is transparent." As an alternative, a bullet should be added for "Steady-state voltage constraint."<br>3. The scheduling time horizon should be clarified.<br>4. The Standards Drafting Team indicated that they have decided not to define the term Existing Transmission Commitments, yet R13 uses that defined term with capital letters. The words Existing Transmission Commitments in R13 and elsewhere in the standard should not be capitalized so as not to indicate a defined term.<br>5. R22 change "covert" to "convert". |
| **Response:** 1.) R1.1 - We have changed the requirement to address this concern – the revised standard requires that contingencies used match those used in operations studies and planning studies for the applicable time periods.<br>2.) R8 – We believe the new language in R2.1.1 (R2.1.1. Any Facility within the Transmission Operator's area based on thermal, stability or voltage limits) addresses this concern.<br>3.) We have asked NAESB to address scheduling timelines and how they relate to the release of unscheduled reservations.<br>4.) We have defined ETC within the standards themselves.<br>5.) We have corrected this typographical error. | |
| MRO | 1. R1.1 implies that the only planning criteria that should be used in ATC calculations is Category B in Table 1 of the NERC Standards. That is incorrect, the methodology should describe how it meets the planning criteria that is appropriate for posted values including applicable NERC Standards, regional criteria, Transmission Owner criteria, etc. Therefore, R1.1 should state that "How methodology meets the planning criteria in NERC Standards, regional standards, Transmission Owner's planning criteria, Transmission Planner's planning criteria, and other applicable planning criteria used by the Transmission Planner to plan the system.<br>2. R8 does not cover all the limitations that are possible for flowgates, for example, the limitation may be due to high transfers causing low voltage on the system after the next condition. This is not an example of a thermal rating or a voltage limit of the power transfer. The MRO suggests that an additional bullet be added to R8 stating "Any other constraint to power transferred across the Flowgate, if applicable. For such constraints, the constraint should be defined, explained, and examples given in the methodology so as to ensure that the ATC methodology is transparent." As an alternative, the MRO recommends that a bullet be added for "Steady-state voltage constraint."<br>3. MRO believes the scheduling time horizon should be clarified.<br>4. The Standards Drafting Team indicated that they have decided not to define the term Existing Transmission Commitments, yet R13 uses that defined term with capital letters. The words Existing Transmission Commitments in R13 and elsewhere in the standard should not be capitalized so as not to indicate a defined term.<br>5. R22 change "covert" to "convert". |

| Question #10 | |
|---|---|
| **Commenter** | **Comment** |
| **Response:** 1.) R1.1 - We have changed the requirement to address this concern – the revised standard requires that contingencies used match those used in operations studies and planning studies for the applicable time periods.<br>2.) R8 – We believe the new language in R2.1.1 (R2.1.1. Any Facility within the Transmission Operator's area based on thermal, stability or voltage limits) addresses this concern.<br>3.) We have asked NAESB to address scheduling timelines and how they relate to the release of unscheduled reservations.<br>4.) We have defined ETC within the standards themselves.<br>5.) We have corrected this typographical error. | |
| SERC ATCWG | The updating of flowgates as specified in Requirement 2 should be annually rather than quarterly. |
| **Response:** Since no other stakeholders disagreed with the 'quarterly' update and since no justification has been provided to support the change, the drafting team left 'quarterly' in the requirement. | |
| SRP | The standard should describe how flowgates and reliability limits should be determined such as is done for the Network Response Methodology MOD028 in requirement R6 and is done for the Rated System Path Methodology MOD029 in requirement R6.<br>Requirements R1.1, R1.2 & R1.3 are fill-in-the-blank requirements and need to specify rather than ask the tsp to explain what they do.<br>R8 - The standard should specify how the thermal, voltage and stability limited are determined. For example, are these n-0 or n-1 limits and are they transient or post-transient? |
| **Response:** 1.) The SDT has modified the standard to address this comment. R2.1 in the revised standard is the process for identifying Flowgates.<br>2.) The SDT has modified the standard to address this comment. R1.1 was moved into R2.1.2 and states, more specifically, how to treat contingencies in the identification of Flowgates. R1.2 and R1.3 were moved into R2.1.3 and identifies, more specifically, how to treat congestion in the identification of Flowgates<br>3.) The SDT has specified in R2.3 that the TFCs must respect SOLs. In the revised standard, the Transmission Operator is assigned responsibility for determining transfer capabilities and, the Transmission Operator will already have the thermal voltage and stability limits through requirements in other standards. | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a standard drafting team on March 17, 2006.

**Description of Current Draft:**

This is the first draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR with consideration of applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Respond to comments. | TBD |
| 2. Post revised standard for stakeholder comment. | TBD |
| 3. Respond to comments. | TBD |
| 4. Post for 30-day pre-ballot review. | TBD |
| 5. First ballot of standard. | TBD |
| 6. Respond to comments. | TBD |
| 7. Recirculation ballot. | TBD |
| 8. 30-day posting before board adoption. | TBD |
| 9. Board adoption. | TBD |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title:** **Rated System Path Available Transfer Capability**

2. **Number:** MOD-029-1

3. **Purpose:** To promote the consistent and uniform application and documentation of Available Transfer Capability (ATC) calculations performed using the Rated System Path method for reliable system operations.

4. **Applicability:**

   **4.1.** Each Planning Coordinator that uses the Rated System Path method to calculate Transfer Capabilities for paths identified in an Available Transfer Capability Implementation Document.

   **4.2.** Each Reliability Coordinator that uses the Rated System Path method to calculate Transfer Capabilities for paths identified in an Available Transfer Capability Implementation Document.

   **4.3.** Each Transmission Service Provider that uses the Rated System Path method to calculate Transfer Capabilities for paths identified in an Available Transfer Capability Implementation Document.

5. **Proposed Effective Date:** To be determined.

## B. Requirements

**R1.** The Planning Coordinator shall provide to its Transmission Service Provider (in the report drafted for a TTC study) a description of the Contingencies and assumptions considered in the study.

**R2.** The Transmission Service Provider shall make publicly available the reports drafted for TTC studies supplied by its Planning Coordinator(s).

**R3.** The Planning Coordinator shall use a model to conduct its TTC studies that includes at least the entire Planning Coordinator Area, as well as critical modeling details from other Planning Coordinator Areas that would impact the Facility or Facilities under study.

**R4.** Each Planning Coordinator shall update the following components of the base case power flow model it uses to determine a TTC for the time horizon being studied:

**R4.1.** Anticipated transmission system configuration

**R4.2.** Facility Ratings

**R4.3.** Load forecast

**R4.4.** Transmission system Elements scheduled to be taken out of or returned to service

**R4.5.** Generation resources scheduled to be in service, to be taken out of service or to be returned to service

**R4.6.** Special Protection System models

**R5.** The Planning Coordinator shall use assumptions in its TTC calculation that are consistent with those it uses in its expansion planning analyses.

**R6.** For each path upon which Transmission Service has been requested, each Planning Coordinator shall:

**R6.1.** Determine the reliability limited TTC for a path by adjusting generation schedules and Load levels to extreme values (without introducing fictitious facilities into the model) to determine the maximum flow that can be simulated on the path while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.

- If it is not possible to simulate a flow sufficiently large to reach a reliability-limited TTC, the TTC of the path is equal to the maximum flow simulated and the path is said to be flow limited.
- If the TTC determined for a path in one direction is reliability limited and the TTC determined for the same path in the other direction is flow limited, the reliability limited TTC may be used for both directions.

**R6.2.** Determine if the TTC for a new or revised path adversely impacts the path ratings or TTC values of existing paths by modeling the flow on the new or revised path at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level, and if there is an adverse impact:

- Limit the TTC for the new or revised path to eliminate the adverse impacts, or
- Follow a local or regional procedure for resolving the impact with the affected parties.

**R6.3.** Ensure that for jointly owned paths, the sum of all owners' allocations is equal to the TTC of the path

**R6.4.** Draft a report to document the steps performed in determining the TTC for the path including the resulting TTC and the Contingencies and assumptions used to determine the resulting TTC.

**R7.** Each Planning Coordinator associated with a Transmission Service Provider shall ensure that TTC for all posted paths for that Transmission Service Provider are calculated and up to date for use within the transfer capability time horizons specified in MOD-001.

**R8.** Each Planning Coordinator associated with a Transmission Service Provider shall make available to the Transmission Service Provider the most current value for TTC for all the posted paths of that Transmission Service Provider and the reports on the TTC studies performed for each path.

**R9.** The Transmission Service Provider shall make publicly available the results, and associated study reports, of the calculations of TTC provided by the Planning Coordinator(s) upon their being made available to the Transmission Service Provider.

**R10.** The Transmission Service Provider shall calculate ATC for the time horizons specified in MOD-001 R2 according to the ATC calculation schedule specified in MOD-001 R5.

**R11.** The Transmission Service Provider shall calculate firm ATC by reducing the TTC by the sum of the impact of firm Existing Transmission Commitments (ETCs), the Capacity Benefit Margin (CBM), and the Transmission Reliability Margin (TRM) allocated to the path.

**R12.** The Transmission Service Provider shall determine the impact of firm ETCs based on the following inputs:

**R12.1.** The transmission capability utilized in serving Native Load commitments, to include Native Load growth, Load forecast error and losses not otherwise included in TRM or CBM.

**R12.2.** The impact of Firm Network Integration Transmission Service serving Load, to include Load forecast error and losses not otherwise included in TRM or CBM.

**R12.3.** The impact of grandfathered firm Transmission Service agreements and bundled contracts for energy and transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or Safe Harbor Tariff accepted by FERC.

**R12.4.** The impact of Firm Point to Point Transmission Service.

**R12.5.** The impact of maintaining roll-over rights for Firm Transmission Service contracts, five years or longer in duration, granting Transmission Customers the right of first refusal to take or continue to take Transmission Service from a Transmission Owner when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**R12.6.** The impact of any Ancillary Services not otherwise included in CBM or TRM,

**R12.7.** Post-backs of redirected or released Firm services.

**R12.8.** The impact of counter-flows not otherwise accounted for in the ATC calculation.

**R12.9.** The impact of any other services, contracts, or agreements not specified above using transmission that serves Native Load or Firm Network Integration Transmission Service

Re: R12.7 — Being discussed at NAESB - may need to be included. Maybe for temporary "undesignation" of a DNR

**R12.10.** The Transmission Service Provider shall calculate non-firm ATC by reducing the TTC by the sum of the firm ETCs, the non-firm ETCs, and the TRM allocated to the path.

**R13.** The Transmission Service Provider shall determine the impact of non-firm ETCs based on the following inputs:

**R14.** The impact of Non-Firm Network Integration Transmission Service serving Load to include Load forecast error and losses not otherwise included in TRM or CBM.

**R14.1.** The impact of grandfathered Non-Firm Transmission Service agreements and bundled contracts for energy and transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or Safe Harbor Tariff accepted by FERC.

**R14.2.** The impact of Non-firm Point to Point Transmission Service.

**R14.3.** The impact of counter-flows not otherwise accounted for in the ATC calculation.

**R14.4.** Capacity utilized for TRM that the Transmission Service Provider has elected to be released for as non-firm ATC.

**R14.5.** Post-backs due to the reinstating of Firm from a "Firm-to-Non-Firm" redirect.

**R15.** The Transmission Service Provider shall increase non-firm ATC by the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC, to the extent allowable by the agreement associated with the service, in accordance with established business practices.

**R16.** The Transmission Service Provider shall make publicly available the ATC for each path.

## C. Compliance

To be added with next posting.

## D. Measures

To be added with next posting.

## E. Regional Differences

None.

## F. Associated Documents

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
| | | | |

Please use this form to submit comments on the 1st draft of standard MOD-029-1 Rated System Path ATC Methodology. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

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   ☐ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☐ Yes

   ☐ No

   Comments:

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☐ No

   Comments:

5. Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

   ☐ Yes

   ☐ No

   Comments:

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**7.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☐ No

Comments:

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments:

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: E. Nic Henery | | |
| Organization: APPA | | |
| Telephone: 202-467-2985 | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** APPA

**Lead Contact:** **E. Nick Henery**

**Contact Organization:** **APPA**

**Contact Segment:** **Segment 1**

**Contact Telephone:** **202-467-2985**

**Contact E-mail:** **nhenery@APPAnet.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Matt Schull | North Carolina Municipal Power Agency #1 | **SERC** | Segment 5 - Electric Generators |
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   ☐ Yes

   ☒ No

   Comments: This is the very reason why it is necessary for the TSP to go the TP, PC , RC or TOP (depending on the time horizon of the ATC calculation) which have determined the TTC for reliable operational and planning reasons. Whatever, method the reliability functions have used will be communicated to the TSP and they will post the values and backup information for the calculations.

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☒ No

   Comments: See my comments on MOD-028

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☐ Yes

   ☐ No

   Comments: R6 and its Sub-requirements are study methodologies that should not be included in any standard. Requirements of this nature could be interpreted to mean that an entities' future plan that included a resource 6 years from now would be fictitious if in the next planning cycle they determined to remove it. These Standards are written in a Policy format.

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: This is a business practice, not reliability.

**5.** Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

☐ Yes

☒ No

Comments: This should be removed, the rules for using CBM should stay in the CBM standards.

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: These are confusing and should be removed. R14 is written in a manner it is impossible to determine which Reliability function is responsible to meet the standard. In addition, any reference to non-firm ATC should be in MOD-001, not spread out through several standards.

**7.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: See Comments on MOD-029

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

☐ Yes

☒ No

Comments: The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings.
FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments: See question 8 above

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments: The Standard is written much like a Policy and it cannot be determined who is responsible for the different calculations of the components of the ATC. The Standard does not provide the Compliance Monitor or the TSP who calculates the Hourly. Daily, and Monthly ATCs with the necessary requirements to know what is necessary to be compliant.

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Stephen Tran | |
| Organization: | BC Transmission Corporation | |
| Telephone: | (604) 699-7363 | |
| E-mail: | stephen.tran@bctc.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

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   ☐ Yes

   ☒ No

   Comments: The use of artificial input data to increase a TTC limit for scenarios analysis and evaluating the impacts of a proposed generator (which is a fictitious until it has been constructed) would not diminish the liabilty of the system.

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☐ No

   Comments:

5. Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

   ☐ Yes

☐ No

Comments:

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**7.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: ATC related standards should be applicable only to entities who have the obligation to provide non-discrimintory transmission service, that is the Transmission Service Providers.

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

☐ Yes

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Comments:

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☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments:

Requirements R3, R4, R5, and R6 are similar to what we are required to do under FAC-010-1. Similarity is good, but in this case there are areas of duplication and inconsistency. For example:

1. FAC-010-1 requires Planning Authorities to have an SOL Methodology that reflects the requirements similar to R3 and R4. Is NERC proposing that they will audit on having an SOL Methodology consistent with FAC-010 and then audit on determining TTCs consistent with MOD-029. What happens if our SOL Methodology differs from MOD-029? It seems that the TTC standard should only require to determine TTCs based on SOLs, which is what FAC-012 requires.

2. Requirement R5 requires the use of assumptions consistent with expansion planning analysis. It is unclear what this means or how this would be audited, except by looking at SOL Methodology, unless we are also required to document our assumptions for MOD-029. This would be duplicative of our SOL Methodology.

3. Requirement R6 is not acceptable because it limits what we can consider in determining TTCs. R6.1, which references TPL-001 and TPL-002, is somewhat consistent with FAC-010. However, the reference should be to FAC-010, System Operating Limits, not the transmission planning standards. TPL-001 and TPL-002 do not have Western Interconnection differences, and TTCs need to allow for consideration of regional differences. Furthermore, we have to ask what is the purpose of BCTC having an SOL Methodology (FAC-010) and determining SOLs according to this Methodology (FAC-014), if MOD-029 provides criteria for determining TTCs. This is setting us up for a reliablity vs. commercial capacity conflict.

4. The second bullet under R6.1 is not acceptable. If a path is flow limited to less than "the reliability limit", how can we provide TTC up to the reliability limit. Firstly, we cannot calculate a reliability limit for anything higher than what will flow on the path (without using fictitious devices). Secondly, how can a customer use it?

Our suggestion to NERC would be to follow the structure layed out in the FAC series. Transmission Owners determine Facility Ratings according to FAC-008 and 009. Based on these Facility Ratings and other factors, Planning Coordinators, Reliability Coordinators, Transmission Planners determine SOLs according to FAC-010, 011,and -014. Based on these SOLs, PCs, RCs, and TSPs determine TTC, etc. according to the applicable NERC standard.

The above comments are also applicable to MOD-28-1 and MOD 30-1

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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   ☐ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☒ No

   Comments: The impact of load growth for Network Integration Transmission Service should be included in R12.2.
   The "five years or longer in duration" language should be removed from R12.5. due to the fact that this element of Order 890 is only to be implemented by a Transmission Service Provider (TSP) once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those existing Customers who have not yet been required to commit to five years of service to retain their roll-over rights.

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☒ Yes

   ☐ No

   Comments: Allowing the use of artificial input data to increase a TTC limit does not represent the most relevent system conditions to establish a reliabilty limit.

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☐ No

Comments:

**5.** Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

☐ Yes

☐ No

Comments:

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**7.** Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority.

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission’s (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC’s directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If “No,” please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments: The ATC MODs (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide narrative descriptions of these methodologies.

The Applicability section 4.1. through 4.3. and R1., R4. through R11., R15., and R16. should be clarified that ATC need only be calculated and posted for Posted Paths, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.

R2. and R9. -- Making TTC study reports publicly available would present system security concerns due to the fact that such studies will identify the most limiting contingencies. Identifying the most critical contingencies publicly could make them a target and thus reduce system reliability. This information should only be shared with those entities demonstrably impacted by such limiting contingencies.

R12.7. and R14.5. -- Please define the term "Post-back".

The current "R14." should be numbered as "R13.1." and this will have an impact on all subsequent requirements.

**WECC MIC MIS ATC Task Force / Attendance Sheet**
**Attendance for WECC-Specific NERC Comments**

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| Steve Tran | BP TX | | | |

Please use this form to submit comments on the 1st draft of standard MOD-029-1 Rated System Path ATC Methodology. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| Telephone: | 870-543-5420 | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| George Bartlett | Entergy Services Inc. | **SERC** | Transmission Owner |
| Jim Case | Entergy Services Inc. | **SERC** | Transmission Owner |
| Ed Davis | Entergy Services Inc. | **SERC** | Transmission Owner |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-029-1 Rated System Path ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-029-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. FERC has ordered that the TTC for all posted paths be calculated by using one of three methodologies (1 Rated System Path, 2 Network Response & 3 Flowbase). The Rated System Path (RSP) Standard (MOD-029-1) is modeled after the WECC Path Rating Methodology which does not require that all posted paths be rated using the WECC Methodology. There are many posted paths within WECC whose ratings were not calculated using the WECC Path Rating process and would need to be re-rated to conform to the RSP Standard. Should the RSP Standard address this issue? If "Yes" please explain how you believe it should be addressed in the comments area.

   ☒ Yes

   ☐ No

   Comments: Each Transmission Service Provider should calculated TTC for all posted using the same method for consistency.

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☒ No

   Comments: We suggest that R12.10 should be a stand alone requirement rather than a sub requirement. R 13 should be a lead requirement with R14 and R 14.1 - R14.5 as sub requirements under R13 requirements. R15 is similar to post back, therefore, it should also be made as a subrequirement under R13.

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: Realistically TTC should be calculated using any controls that can impact flow on the path. By not using all controls such as phase shifting transformers, TTC values are lower than what they can practically be, therefore, potential of underutilizing the transmission system.

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: Sale of service should not be in scope of this standard, only how TTCs and ATCs are calculated should be included. Accounting for Non-Firm Transmission already sold multiple times should be included in this standard so that accurate ATCs can be calculated and offered for sale to the market place. Sale of Non-Firm Transmission multiple times is a commercial issue and should be addressed by NAESB Business Practice Standard.

**5.** Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

☒ Yes

☐ No

Comments: For consistency with other methods, excluding CBM from Non-Firm ETC should be included in this standard..

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: Please see comments to Question 2 above.

**7.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☒ Yes

☐ No

Comments:

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

☒ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments: R1- it is not clear which "report drafted for a TTC study" is referred to and what study is conducted. R3 - "critical modeling details" is vague and should be explained. R3 and R4 - it appears that only one model is used for calculation of TTC for all paths and time horizons, if yes, it appears unrealistic, if no, model should be made plural. R4 - are Long Term Firm Transmission Service Reservations included in base cases? If so, these should be included as subrequirement under R4. R4 - R4 should include planned and unplanned outages, if included in the base case. R6.2 refers to path rating - is it same as TTC of that path, if so, only TTC based on path rating should be used. R6.2, it is not clear what is "revised path". R6.2 second bullet - are local or regional procedures approved by any entity? These should be included in the data to be made publicly available and included in R9. R8 - it appears like each Planning Coordinator determine TTC for all posted path of Transmission Service Provider. "value" should be made plural. It is not clear how frequently TTC values are calculated or updated.

Please use this form to submit comments on the 1st draft of standard MOD-029-1 Rated System Path ATC Methodology. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☒ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-029-1 Rated System Path ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-029-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

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   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

5. Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

   ☒ Yes

   ☐ No

   Comments: See IRC comments submitted by Charles Yeung.

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: See IRC comments submitted by Charles Yeung.

**7.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

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Comments: See IRC comments submitted by Charles Yeung.

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

☒ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area and there has been no reservation of transmission capacity in ERCOT.

Available Transfer Capability is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. The ERCOT Interconnection has already moved "beyond" ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therfore both ERCOT and SPP are notified when the DC Tie capability is reduced.

Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.

In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.

In the current and future ERCOT market design the method of calculating ATC, TTC and the use of CBM and TRM are not applicable to the ERCOT Interconnection. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments: See IRC comments submitted by Charles Yeung.

Please use this form to submit comments on the 1st draft of standard MOD-029-1 Rated System Path ATC Methodology. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Richard Kovacs | FirstEnergy Corp. EDPP | | |
| Phil Bowers | FirstEnergy Corp. EDPP | | |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-029-1 Rated System Path ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-029-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. FERC has ordered that the TTC for all posted paths be calculated by using one of three methodologies (1 Rated System Path, 2 Network Response & 3 Flowbase). The Rated System Path (RSP) Standard (MOD-029-1) is modeled after the WECC Path Rating Methodology which does not require that all posted paths be rated using the WECC Methodology. There are many posted paths within WECC whose ratings were not calculated using the WECC Path Rating process and would need to be re-rated to conform to the RSP Standard. Should the RSP Standard address this issue? If "Yes" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☒ No

   Comments:

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: Permitting the arbitrary introduction of fictitious devices potentially encourages producing the limitation wanted rather than determining the actual limitation. First bullet in R6.1 says the path will be said to be "flow limited", which is a misleading characterization. It really would be "extreme value limited" and should be identified as such. The second bullet in R6.1 seems to be very arbitrary and should be deleted to result in a limit that more accurately reflects the actual ability of the system to transfer power.

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: This is better covered by NAESB as a business practice issue. However, the requirements for loading and unloading the interchange schedules associated with this practice should be included in the NERC Standards to ensure that reliability is not jeopardized.

**5.** Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

☐ Yes

☒ No

Comments: MOD-004 should contain all the rules related to CBM. However, R13 and R14 should be renumbered to reflect the appropriate formatting.

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: They should be combined to strengthen the reader's understanding of the material.

**7.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☒ Yes

☐ No

Comments: MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once, eliminate duplication, and simplify the applicability sections of MOD-028, 029, and 030

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

☒ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments: R6.2 demonstrates the essential difference with Network Response ATC calculations.

R11 should be revised to eliminate the subtraction of a portion of TRM from TTC to calculate ATC since this has already occurred in R6.2 where parallel path impacts are covered.

Please use this form to submit comments on the 1st draft of standard MOD-029-1 Rated System Path ATC Methodology. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
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| E-mail: | champagne.roger.2@hydro.qc.ca | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Danielle Beaulieu | Hydro-Québec TransÉnergie | **NPCC** | 1 |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. FERC has ordered that the TTC for all posted paths be calculated by using one of three methodologies (1 Rated System Path, 2 Network Response & 3 Flowbase). The Rated System Path (RSP) Standard (MOD-029-1) is modeled after the WECC Path Rating Methodology which does not require that all posted paths be rated using the WECC Methodology. There are many posted paths within WECC whose ratings were not calculated using the WECC Path Rating process and would need to be re-rated to conform to the RSP Standard. Should the RSP Standard address this issue? If "Yes" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☐ No

   Comments: .

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

   ☒ Yes

   ☐ No

   Comments: R12.10 should be renumbered R13, R13 should be renumbered R14, R14 should be renumbered R14.1, R14.1 should be renumbered R14.2 (etc.)

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☒ Yes

   ☒ No

   Comments: Real-time system reliability would not be diminished since the actual power transfer is less than the reliability limit. However, long-term reliabilty could be diminished because posted TTC would be higher than the actual maximum flow. Transmission users could overestimate the path capacity and consequently overesimate the amount of power that can be delivered on this specific path. A path might be voltage limited, not flow limited, and the introduction of a fictitious generator might hide the reliability rating if it supports the voltage on the path in the simulation, but not in "real life".

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

Comments: As requested in R12.10, non-firm ATC is calculated by reducing TTC by non-firm-ETCs. Depending on time horizon, unscheduled transmission service could be sold multiple-times This is a business issue that should be addressed by NAESB.

**5.** Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

☐ Yes

☒ No

Comments: This is a business issue to be addressed by NAESB.

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: R14 is for planning and operating horizons and R15 is only for operating horizon

**7.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☒ Yes

☒ No

Comments: MOD-029 includes applicability to Reliability Coordinator, but there is no reference in the details of the standard to the RC. A role should be defined, or RC should be removed from the Applicability section. All MOD standards should be consisent in their description of the roles for providing input and calculating ATC.

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments: We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments: for clarification

R6.1 Regional criteria (NPCC) are not all included in TPL-001 and TPL002 for contingencies in Table 1, category B…There should be acknowledgement that there can be regional differences in the application of planning criteria that may extend beyond Category B contingencies in determination of TTC.

R.12.10 (re-numbered to R13) : Note that the TRM allocated to the path for non-firm ATC may be less than the TRM for firm ATC.

R12.10 (renumbered to R13): As it is not specified , we understand that the TSP is free to calculate the ATC by reducing the TTC by reserved or by scheduled transmission services depending on the time horizon.

R11: Use of the word "impact" in the formula for ATC introduces confusion. Can R11 be written in formula format like the Version Zero standards?

R11.4 Use of the word "impact" is redundant.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
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| Name: | Ron Falsetti |
| Organization: | IESO |
| Telephone: | 905-855-6187 |
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| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
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**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☐ Yes

   ☐ No

   Comments: No Comments.

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☒ No

   Comments: We feel that R12.1, R12.2, R12.6 and R14 leave room for double counting for components that shold have been taken care of by TRM and CBM. Further, details to be included for non-firm ATC calculation are missing in R13.

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: Reliability would not be diminished by incorporating fictitious devices into power flow simulations. This practice is not uncommon in the determination of operating limits and TTCs when available resources are insufficient to stress an interface or transfer level to the "edge" or for other practical modeling reasons. However, entities which use such fictitious devices must ensure that its modeling assumptions are shared with other possible affected entities.

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: This seems to be a business practice issue. Similar issues are selling non-firm services out of TRMs and/or CBMs which may be recalled when these latter components need to be used for capacity needs or transmission reliability needs.

**5.** Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

☒ Yes

☐ No

Comments: It needs to be, but then again it may be a business practice issue. Along this vein, MOD-028 is silent on this and also has no mention of the CBM quantity in the calculation of non-firm ATC.

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: R14 and R15 could be combined. However, in R15, we do not understand what would be the items that are "the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC,.."

**7.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: Unlike the other MOD standards, this standard more appropriately reflect the role of the PC and RC in the determination of transfer capabilities, not ATC. However, the applicability section gives rise to unclear responsibilities between TSP and the PC/RC in that both calculate transfer capabilities of the "paths". We feel that the PC and RC are responsible for calculating the total path capability, whereas the TSP is responsible for calculating the available path capability. This distinction needs to applied to all the MOD standards.

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

☒ Yes

☒ No

Comments: It appears that the SDT has addressd all of the FERC directives. However, in view of the many comments provided to this and the other related MOD standards, and hence substantive changes are expected, we see the need to revisit this subject again when revised standards are posted.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: No, but please note that some markets do not offer physical transmission services and hence some of the requirements in this standard do not apply to these entities.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments: Please see our comments on the supplementary SAR.

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Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | IRC Standards Review Committee |
| **Lead Contact:** | **Charles Yeung** |
| **Contact Organization:** | **SPP** |
| **Contact Segment:** | **2** |
| **Contact Telephone:** | **823-724-6142** |
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| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Jim Castle | NYISO | **NPCC** | |
| Alicia Daugherty | PJM | **RFC** | |
| Ron Falsetti | IESO | **NPCC** | |
| Matt Goldberg | ISO-NE | **NPCC** | |
| Brent Kingsford | CAISO | **WECC** | |
| Steve Myers | ERCOT | **ERCOT** | |
| Anita Lee | AESO | **WECC** | |
| Bill Phillips | MISO | **RFC+** | |
| | | **MRO+** | |
| | | **SERC+** | |
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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-029-1 Rated System Path ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-029-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. FERC has ordered that the TTC for all posted paths be calculated by using one of three methodologies (1 Rated System Path, 2 Network Response & 3 Flowbase). The Rated System Path (RSP) Standard (MOD-029-1) is modeled after the WECC Path Rating Methodology which does not require that all posted paths be rated using the WECC Methodology. There are many posted paths within WECC whose ratings were not calculated using the WECC Path Rating process and would need to be re-rated to conform to the RSP Standard. Should the RSP Standard address this issue? If "Yes" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☒ No

   Comments: We do not believe the RSP Standard needs to specifically address WECC Path ratings which were not rated using the WECC Path Rating process.

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☒ No

   Comments: We feel that R12.1, R12.2, R12.6 and R14 leave room for double counting for components that shold have been taken care of by TRM and CBM. Further, details to be included non-firm ATC calculation are missing in R13.

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: Reliability would not be diminished by fictitions simulations. This practice is not uncommon in the determination of operating limits and TTCs when available resources are insufficient to stress an interface or transfer level to the "edge".

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: This seems to be a business practice issue. Similar issues are selling non-firm services out of TRMs and/or CBMs which may be recalled when these latter components need to be used for capacity needs or transmission reliability needs.

**5.** Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

☒ Yes

☐ No

Comments: It needs to be, but then again it may be a business practice issue. Along this vein, MON-028 is silent on this and also has no meniton of the CBM quantity in the calculation of non-firm ATC.

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: R14 and R15 may be combined. However, in R15, we do not understand what would be the items that are "the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC,.."

**7.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: Unlike the other MOD standards, this standard more appropriately reflect the role of the PC and RC the determination of transfer capabilities, not ATC. However, the applicability section gives rise to unclear responsibilities between TSP and the PC/RC in that both calculate transfer capabilities of the "paths". We feel that the PC and RC are responsible for calculating the total path capability, whereas the TSp is responsible for calculating the available path capability.

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

☒ Yes

☒ No

Comments: It appears that the SDT has addressd all of the FERC directives. However, in view of the many comments provided to this and the other related MOD standards, and hence substantive changes are expected, we see the need to revisit this subject again when revised standards are posted.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: No, but please note that some markets do not offer physical transmission services and hence some of the requirements in this standard do not apply to these entities.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments: Please see our comments on the supplementary SAR.

Please use this form to submit comments on the 1st draft of standard MOD-029-1 Rated System Path ATC Methodology. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Tom Mielnik | |
| Organization: | MidAmerican Energy Company | |
| Telephone: | 563-333-8129 | |
| E-mail: | tcmielnik@midamerican.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☒ **MRO** | ☒ | 3 — Load-serving Entities |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☐ No

   Comments:

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☐ Yes

   ☐ No

   Comments:

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☐ No

   Comments:

5. Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

   ☐ Yes

   ☐ No

   Comments:

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**7.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☐ No

Comments:

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☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments: Our footprint does not include facilities in the WECC, therefore, I do not answer all the questions on the MOD-029-1 but provides the following comments: 1. The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The purpose in MOD-028-1 be revised to replace "uniform" with "transparent"

2. The Functional Entity as provided in A.4. should not be qualified, for example, A.4. should just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider. 3. For R1, R3, R4, R5, R6, R7, and R8, the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. 4. R6.1 refers to only certain NERC planning criteria, when the TTC must be based upon the appropriate planning criteria whatever that is. The references to planning criteria should be expanded to include all applicable planning criteria, including NERC, regional, subregional, Transmission Owner, etc. 5. R2, R9, R16 and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available

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Group Comments (Complete this page if comments are from a group.)

**Group Name:** Midwest Reliability Organization (MRO)

**Lead Contact:** **Tom Mielnik**

**Contact Organization:** **MRO for Group (MEC for lead contact)**

**Contact Segment:** **10**

**Contact Telephone:** **563-333-8129**

**Contact E-mail:** **tcmielnik@midamerican.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Neal Balu | WPS | **MRO** | 10 |
| Terry Bilke | MISO | **MRO** | 10 |
| Robert Coish, Chair | MHEB | **MRO** | 10 |
| Carol Gerou | MP | **MRO** | 10 |
| Ken Goldsmith | ALT | **MRO** | 10 |
| Todd Gosnell | OPPD | **MRO** | 10 |
| Jim Haigh | WAPA | **MRO** | 10 |
| Joe Knight | GRE | **MRO** | 10 |
| Pam Oreschnick | XEL | **MRO** | 10 |
| Dave Rudolph | BEPC | **MRO** | 10 |
| Eric Ruskamp | LES | **MRO** | 10 |
| Mike Brytowski, Secretary | MRO | **MRO** | 10 |
| 28 Additional MRO Members | Not Named Above | **MRO** | 10 |
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   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

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   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☐ No

   Comments:

5. Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

   ☐ Yes

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   Comments:

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☐ Yes

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Comments:

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☐ Yes

☐ No

Comments:

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Comments: The MRO footprint does not include facilities in the WECC, therefore, the MRO does not answer all the questions on the MOD-029-1 but provides the following comments: 1. The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The MRO recommends that the purpose in MOD-028-1 be revised to replace "uniform" with "transparent"

2. The MRO believes that the Functional Entity as provided in A.4. should not be qualified, for example, the MRO recommends that A.4. just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider. 3. The MRO believes that for R1, R3, R4, R5, R6, R7, and R8, the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. 4. R6.1 refers to only certain NERC planning criteria, when the TTC must be based upon the appropriate planning criteria whatever that is. The references to planning criteria should be expanded to include all applicable planning criteria, including NERC, regional, subregional, Transmission Owner, etc. 5. R2, R9, R16 and other requirements that indicate that the results are to be made available

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|---|---|---|
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| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | NPCC CP9 Reliability Standards Working Group |
| **Lead Contact:** | **Guy V. Zito** |
| **Contact Organization:** | **Northeast Power Coordinating Council** |
| **Contact Segment:** | **10** |
| **Contact Telephone:** | **212-840-1070** |
| **Contact E-mail:** | **gzito@npcc.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Kathleen Goodman | ISO-New England | **NPCC** | 2 |
| Al Adamson | New York State Reliability Council | **NPCC** | 10 |
| Ralph Rufrano | New York Power Authority | **NPCC** | 1 |
| Grag Campoli | New York ISO | **NPCC** | 2 |
| Roger Champagne | HydroQuebec TransEnergie | **NPCC** | 1 |
| Guy V. Zito | NPCC | **NPCC** | 10 |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

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1. FERC has ordered that the TTC for all posted paths be calculated by using one of three methodologies (1 Rated System Path, 2 Network Response & 3 Flowbase). The Rated System Path (RSP) Standard (MOD-029-1) is modeled after the WECC Path Rating Methodology which does not require that all posted paths be rated using the WECC Methodology. There are many posted paths within WECC whose ratings were not calculated using the WECC Path Rating process and would need to be re-rated to conform to the RSP Standard. Should the RSP Standard address this issue? If "Yes" please explain how you believe it should be addressed in the comments area.

   ☐ Yes

   ☐ No

   Comments: .

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

   ☒ Yes

   ☐ No

   Comments: R12.10 should be renumbered R13, R13 should be renumbered R14, R14 should be renumbered R14.1, R14.1 should be renumbered R14.2 (etc.)

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

   ☒ Yes

   ☒ No

   Comments: Real-time system reliability would not be diminished since the actual power transfer is less than the reliability limit. However, long-term reliabilty could be diminished because posted TTC would be higher than the actual maximum flow. Transmission users could overestimate the path capacity and consequently overesimate the amount of power that can be delivered on this specific path. A path might be voltage limited, not flow limited, and the introduction of a fictitious generator might hide the reliability rating if it supports the voltage on the path in the simulation, but not in "real life".

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

Comments: As requested in R12.10, non-firm ATC is calculated by reducing TTC by non-firm-ETCs. Depending on time horizon, unscheduled transmission service could be sold multiple-times This is a business issue that should be addressed by NAESB.

**5.** Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

☐ Yes

☒ No

Comments: This is a business issue to be addressed by NAESB.

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: R14 is for planning and operating horizons and R15 is only for operating horizon

**7.** Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities to whom you believe the standard should apply and why.

☒ Yes

☒ No

Comments: MOD-029 includes applicability to Reliability Coordinator, but there is no reference in the details of the standard to the RC. A role should be defined, or RC should be removed from the Applicability section. All MOD standards should be consisent in their description of the roles for providing input and calculating ATC.

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission’s (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC’s directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If “No,” please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☐ No

Comments: We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments: for clarification

R6.1 Regional criteria (NPCC) are not all included in TPL-001 and TPL002 for contingencies in Table 1, category B…There should be acknowledgement that there can be regional differences in the application of planning criteria that may extend beyond Category B contingencies in determination of TTC.

R.12.10 (re-numbered to R13) : Note that the TRM allocated to the path for non-firm ATC may be less than the TRM for firm ATC.

R12.10 (renumbered to R13): As it is not specified , we understand that the TSP is free to calculate the ATC by reducing the TTC by reserved or by scheduled transmission services depending on the time horizon.

R11: Use of the word "impact" in the formula for ATC introduces confusion. Can R11 be written in formula format like the Version Zero standards?

R11.4 Use of the word "impact" is redundant.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

| Group Comments (Complete this page if comments are from a group.) | |
|---|---|
| **Group Name:** | Public Service Commission of South Carolina |
| **Lead Contact:** | **Phil Riley** |
| **Contact Organization:** | **Public Service Commission of South Carolina** |
| **Contact Segment:** | **9** |
| **Contact Telephone:** | **803-896-5154** |
| **Contact E-mail:** | **philip.riley@psc.sc.gov** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
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| G. O'Neal Hamilton | PSCSC | **SERC** | 9 |
| John E. "Butch" Howard | PSCSC | **SERC** | 9 |
| Randy Mitchell | PSCSC | **SERC** | 9 |
| C. Robert "Bob" Moseley | PSCSC | **SERC** | 9 |
| David A. Wright | PSCSC | **SERC** | 9 |
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   ☐ Yes

   ☒ No

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   ☒ Yes

   ☐ No

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   ☐ Yes

   ☐ No

   Comments: Our comments are from a regulatory perspective. This is strictly a technical issue.

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

   ☐ Yes

   ☐ No

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   ☐ No

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☒ Yes

☐ No

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<table>
<tr><th colspan="3">Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name: Chuck Falls</td></tr>
<tr><td colspan="3">Organization: Salt River Project</td></tr>
<tr><td colspan="3">Telephone: 602 236-0965</td></tr>
<tr><td colspan="3">E-mail: Chuck.Falls@srpnet.com</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☐ NPCC<br>☐ RFC<br>☐ SERC<br>☐ SPP<br>☒ WECC<br>☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
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</table>

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**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☒ Yes

   ☐ No

   Comments: SRP supports the comments on this subject submitted by the WECC contingent. Additionally we suggest that the drafting team provide for a "phasing-in" period to allow time for the TSP's who use the Rated System Path Methodology to re-study the TTC for their Posted Paths. This is needed because of the large number of Posted Paths in the west whose TTC was not established by the rigorous methodology stipulated in the R6 of the new standard. If a "phasing-in" period is not appropriately addressed in the standard itself it needs to be provided for somewhere. We suggest an Implementation Plan similar to the CIP Standards. One that requires the Responsible Entities to become Substantially Compliant, Compliant, and then Audibly Compliant within a defined schedule.

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   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☒ No

   Comments: The system should be reliable if the TTC in both directions of all paths is reliability limited even if one or more of the reliability limits was found using fictitious devices for stressing the system in order to determine the reliability limit. The flow limit does not represent the capability of the transmission system to reliably transfer power. It does represent the limit of the capability of the system to stress the system which doesn't imply the limit beyond which reliability is in jeopardy.

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**5.** Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

☐ Yes

☐ No

Comments:

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☐ Yes

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☐ Yes

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☐ Yes

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☐ No

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: W. Shannon Black Et Al ; Sacramento Municipal Utility District | | |
| Organization: Sacramento Municipal Utility District | | |
| Telephone: (916) 732-5734 | | |
| E-mail: sblack@smud.org | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** WECC MIC MIS ATC TF

**Lead Contact:** **W Shannon Black**

**Contact Organization:** **Sacramento Municipal Utility District**

**Contact Segment:** **Various**

**Contact Telephone:** **(916) 732-5734**

**Contact E-mail:** **sblack@smud.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| The 24 individuals listed in this same section for MOD-01 comments, filed jointly with this filing, by the WECC MIC MIS ATC TF Team, have either actively monitored this work product or have actively engaged in drafting the attached comments. That Team list of 24 individuals applies to jointly to MOD-01; MOD-04; MOD-08; MOD-29 and MOD-30. | | | |
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The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comments on the proposed requirements and structure of MOD-029-1 Rated System Path ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-029-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "RSP ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. FERC has ordered that the TTC for all posted paths be calculated by using one of three methodologies (1 Rated System Path, 2 Network Response & 3 Flowbase). The Rated System Path (RSP) Standard (MOD-029-1) is modeled after the WECC Path Rating Methodology which does not require that all posted paths be rated using the WECC Methodology. There are many posted paths within WECC whose ratings were not calculated using the WECC Path Rating process and would need to be re-rated to conform to the RSP Standard. Should the RSP Standard address this issue? If "Yes" please explain how you believe it should be addressed in the comments area.

   ☒ Yes

   ☐ No

   Comments:

   The TTC determinative process for the Rated System Path methodology accurately resides in the MOD-29. The WECC Team suggests that these determinants be fully vetted through the augmented expertise of those being added to the team via the most recent ATC SAR.

   The WECC Team does not believe it is FERC's intent to require a posting of TTC for each and every path and each and every possible permutation of paths or POR/PODs within a utility's system. It is estimated that this could result in a million plus postings for some utilities; most of these posting would be on paths for which no service has been requested.

   Rather, FERC has already made it clear that as to posting of ATC and TTC, FERC's intent was stated in its approved definition of "Posted Path." It is the "Posted Path" that requires a posting of ATC and TTC. The WECC Team has the below positive suggestions that will remedy many concerns for MOD-29.

   Suggested Remedy:

   18 CFR 37.6, Order 889/RM95-9-000, P. 58-60 and NAEBS R-4005 all utilize "Posted Path" as the delineated paths for which ATC and TTC must be posted.

   At 18 CFR 37.6, the defintion for Posted Path states: (control area has been replaced with Balancing Authority to bring the defintion in line with the Functional Model)

   Posted Path means: 1) any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. See also: 18 CFR 37.6; http://a257.g.akamaitech.net/7/257/2422/12feb20041500/edocket.access.gpo.gov/cfr_2004/aprqtr/pdf/18cfr37.5.pdf

   First, in refining this draft the term "Posted Path" must be adopted in accordance with FERC's intent.

   The WECC MIC MIS ATC TF Team suggests the following rewrite of R6:

– R6. For each Posted Path, each Planning Coordinator shall determine TTC using the applicable method below:

–

– R6.1. For Posted Paths whose capacity is limited by thermal, voltage or stability limits, TTC shall be the lesser of the thermal, voltage or stability limits as determined by adjusting generation dispatch, area interchange schedules, and Load levels to maximum values (without introducing fictitious facilities or unrealistic values into the system model) to determine the maximum flow that can be simulated on the path while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.

–

– • If it is not possible to simulate a flow sufficiently large to reach a reliability-limited TTC, the TTC of the path is equal to the maximum flow simulated and the path is said to be flow limited.

–

– • If the TTC determined for a path in one direction is reliability limited and the TTC determined for the same path in the other direction is flow limited, the reliability limited TTC may be used for both directions.

–

– R6.2. For Posted Paths whose capacity is limited by contract, TTC shall be set on the Posted Path at the maximum allowable contract capacity, not to exceed the thermal, voltage or stability limits of that Posted Path.

–

– R6.3 For Posted Paths whose capacity is jointly owned, TTC shall be set for each separate owner of the Posted Path at the maximum capacity owned by each separate owner.

~ R6.3.1. The Transmission Service Provider shall ensure that for jointly owned paths, the sum of all owners' allocations is equal to the TTC of the path

–

– R6.4. For Posted Paths whose capacity has been established for ten years or more (subject to contingency and seasonal adjustment), and that are known to have operated reliably at that established capacity rating, TTC shall be set on the Posted Path at the established, reliable level at which that Posted Path has been operating for at least the previous ten years.

–

– R6.5. For new or revised Posted Paths, the Planning Coordinator shall determine if the TTC adversely impacts the path rating or TTC values of existing paths by modeling the flow on the new or revised Posted Path at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level, and if there is an adverse impact:

–

– • Limit the TTC for the new or revised path to eliminate the adverse impacts, or

–

– • Follow a local or regional procedure for resolving the impact with the affected parties.

–

–

R6.6. Draft a report to document the steps performed in determining the TTC for the Posted Path.

**2.** Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

☐ Yes

☒ No

Comments:

The impact of load growth for Network Integration Transmission Service should be included in R12.2.

**3.** Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**4.** Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: The incremental sells of the same non-firm transmission to multiple customers represents a prioritization issue that would best be addressed in a NAESB Busines Practice.

**5.** Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

☒ Yes

☐ No

Comments: As drafted the standard is unclear. This team suggests language that better reflects the following: Order 890, P. 351. "The Commission also required transmission providers to make any transfer capability set aside for CBM available on a non-firm basis and to post this availability on OASIS."

For clarity, this statement needs to be reconciled with MOD-04-1, R.3.4 stating, "The Transmission Service Provider shall use "zero" as the value for all unscheduled CBM for all non-firm ATC calcualtions for all methodlogies. Order 890. P. 262.

**6.** Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: Merely combining these may not be sufficient to make clear what the TSP is supposed to do. R14 should, at minimum, be a subset of R13, lest there be no responsible party. Adding R15 as a subset of R13 would be appropriate.

Some in WECC assert that all "non-firm" is a business practice to be determined by NAESB. Others believe "non-firm" shoud be addressed in MOD-01 - not here.

**7.** Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities to whom you believe the standard should apply and why.

☐ Yes

☒ No

Comments: Although the "Applicability" section states it is applicatable to Relaibility Coordinators, there is nothing in the draft that applies to an RC.

**8.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

☐ Yes

☐ No

Comments: No comment.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

Comments:

A.

The current "R14." should be numbered as "R13.1." and this will have an impact on all subsequent requirements.

B.

In the "Applicability" section, the term "Available Transfer Capability Implementation Document" is used as a defined term. The term is used in MOD-01 R3. At minimum the ATCID either needs to be defined or a reference to the MOD-01 must be inserted for cross reference into each Standard in which it appears.

C.

R1. Change the determinant from "the" to "a" in the parenthetical.

D.

In the "Applicability" section, either "Planning Coordinator" needs to be defined and imported into the NERC Glossary or a more appropriate entity such as "Planning Authority" may be in order.

E.

R6. The term "extreme" is overly vague. This Team suggests replacement with the words "maximum or minimum".

F.

R7-R8. Change "posted path" to "Posted Path".

As with MOD-08, Posted Path should be defined as:

Posted Path

Posted Path means: 1) any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.

G.

The term "postbacks" appeared in Order 890, P. 212. "Therefore, we direct public utilities, working through NERC, to modify related ATC standards by implementing the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows." Since the term is not defined and whereas FERC did not specify exactly what it is, the NERC Team should clarify what FERC meant by the term before inserting it into the calculation process.

H. R6. Everytime the word "path" is used it should be replaced with "POSTED PATH."

I. To assist the industry in determining which of the three methodologies is best suited for the TSP's needs, it is suggested that a statement be inserted into the "Purpose" section of MOD-28 / 29 / 30 stating its intended use.

E.g.

MOD-28 was modeled on the ATC process of much of the Eastern Interconnect.

MOD-29 was modeled on the ATC process of much of the WECC Interconnet.

I.

R12.5 Delete "five years or longer in duration."

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Consideration of Comments — 2nd Draft of Standard MOD-029-1 — Rated System Path ATC (Project 2006-07)

The ATC Standard Drafting Team requesters thank all commenters who submitted comments on the first draft of standard MOD-029-1, Rated System Path ATC (Project 2006-07). This standard was posted for a 30-day public comment period from May 25 through June 24, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 15 sets of comments, including comments from 72 different people from more than 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received from stakeholders, comments from the cooperative effort with NAESB in developing associated business practices, and comments received from FERC staff, the drafting team has significantly redrafted the standard. The changes have been so extensive that the revised standard bears very little resemblance to the last posted draft.

Major changes include:

- Title shortened to 'Rated System Path Methodology'
- Purpose statement revised to clarify that the purpose is to increase consistency and transparency in the development of transfer capability calculations rather than to promote consistent and uniform application and documentation of ATC calculations
- Applicability modified so that the requirement are assigned to the Transmission Operator and Transmission Service Provider – the Planning Coordinator and Reliability Coordinator are not assigned any requirements in the revised standard
- Eliminated R2, R9, and R16, requirements associated with making information 'publicly available' – NAESB business practices will address all posting requirements
- Rearranged the order of the requirements so that the sequence follows a more logical order. R1 (requires the documentation associated with the determination of TTC be organized in a report) was moved into R2 as the last step in the process of determining TTC.
- Put all the modeling requirements (R2 and R4) into a single requirement – R1.
- Deleted R5, the requirement to use assumptions consistent with those used in expansion planning, because the revised MOD-001 — Available Transfer Capability includes a requirement that addresses the same topic but is more comprehensive.
- R6 is the requirement that includes the steps in the process of determining TTC and this requirement was modified based on stakeholder comments to include consideration of Posted Paths limited by contract and to require the development of a nomogram under specific conditions. The step in the process that addressed situations where the TTC for a path is reliability-limited in one direction and flow-limited in the other direction.
- R7 and was a requirement for the Planning Coordinator to ensure TTCs were calculated and this has been deleted. In the revised standard the requirement to calculate TTCs is assigned to the Transmission Operator and is addressed in R2.

- R8 was a requirement for the Planning Coordinator to distribute its TTCs and the supporting information and this requirement has been deleted. In the revised standard the Transmission Operator is required to distribute the TTCs it has developed and this is addressed in R3.
- R10 was a requirement to calculate ATC at specified intervals and this requirement has been deleted. The revised MOD-001 — Available Transfer Capability includes the requirement to calculate ATC at specified intervals.
- R11 described how to calculate firm ATC and in the revised standard the descriptive language has been converted into an algorithm with each of the elements in the algorithm clearly defined. See R7 in the revised standard.
- R12 was a requirement to determine the impact of firm ETCs and this has been converted into an algorithm with each of the elements in the algorithm clearly defined. See R 5 in the revised standard.
- R13 and R14 were requirements to determine the impact of non-firm ETCs and these have been converted into an algorithm with each of the elements in the algorithm clearly defined. See R 6 in the revised standard. (Note that the posted version of the standard had a typographical error that separated R13 into two requirements and this had not been intended.)
- R15 was a requirement related to non-firm ATC and this deleted as a separate requirement – the revised standard includes a specific algorithm for the determination of non-firm ATC that includes the intent of R15 in the definition of 'postbacks.'
- Added measures and compliance elements.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Anita Lee – (G2) | AESO | | ✓ | | | | | | | | |
| 2. | Jason Murray (G6) | AESO | | ✓ | | | | | | | | |
| 3. | Ken Goldsmith - (G3) | ALT | ✓ | | | | ✓ | | | | | |
| 4. | E. Nick Henery – (G1) | APPA | ✓ | | | | | | | | | |
| 5. | Jerry Smith (G6) | APS-TP | | | | | | | | | | |
| 6. | Stephen Tran | BC Transmission Corp. | | ✓ | | | | | | | | |
| 7. | Dave Rudolph - (G3) | BEPC | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 8. | Steve Tran (G6) | BP TX | | | | | | | | | | |
| 9. | Abbey Nulph (G6) (I) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 10. | Rebecca Berdahl (G6) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 11. | Steve Knudsen (G6) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 12. | Charles Mee (G6) | CA Dept Water & Power | | | | | | | | | | |
| 13. | Brent Kingsford – (G2) | CAISO | | ✓ | | | | | | | | |
| 14. | Greg Ford (G6) | CISO-TP | | ✓ | | | | | | | | |
| 15. | Ed Davis | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 16. | George Bartlett | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 17. | Jim Case | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 18. | Narinder K. Saini | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 19. | Steve Myers – (I) (G2) | ERCOT | | ✓ | | | | | | | | ✓ |
| 20. | Patricia vanMidde (G6) | FERC Case MRG, Sempra | | | | | | | | | | |
| 21. | Dave Folk | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 22. | Phil Bowers | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 23. | Richard Kovacs | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 24. | Joe Knight - (G3) | Great River Energy | ✓ | | ✓ | | ✓ | | | | | |
| 25. | Danielle Beaulieu | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 26. | Roger Champagne – (I) (G4) | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 27. | Ron Falsetti – (I) (G2) | IESO | | ✓ | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 28. | Lou Ann Westerfield (G6) | IPUC-SP | | | | | | | | | | |
| 29. | Charles Yeung – (G2) | IRC | | ✓ | | | | | | | | |
| 30. | Matt Goldberg – (G2) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 31. | Kathleen Goodman– (G4) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 32. | Sueyen McMahon (G6) | LADWP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 33. | Eric Ruskamp - (G3) | LES | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 34. | Robert Coish - (G3) | Manitoba Hydro Electric Board (MHEB) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 35. | Tom Mielnik – (I) (G3) | MidAmerican Energy Company (MEC) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 36. | Carol Gerou - (G3) | Minnesota Power (MP) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 37. | Bill Phillips – (G2) | MISO | | ✓ | | | | | | | | |
| 38. | Terry Bilke - (G3) | MISO | | ✓ | | | | | | | | |
| 39. | Mike Brytowski - (G3) | MRO | | | | | | | | | | ✓ |
| 40. | Grag Campoli | New York ISO (NYISO) | | ✓ | | | | | | | | |
| 41. | Jim Castle – (G2) | New York ISO (NYISO) | | ✓ | | | | | | | | |
| 42. | Ralph Rufrano | New York Power Authority (NYPA) | ✓ | | ✓ | | | | | | | |
| 43. | Al Adamson – (G4) | New York State Reliability Council | | | | | | | | | | ✓ |
| 44. | Matt Schull – (G1) | North Carolina MPA (NCMPA) | | | ✓ | ✓ | ✓ | ✓ | | | | |
| 45. | Guy V. Zito – (G4) | NPCC | | | | | | | | | | ✓ |
| 46. | Todd Gosnell - (G3) | OPPD | ✓ | | ✓ | | | ✓ | | | | |
| 47. | Brian Weber (G6) | Pacificorp | ✓ | | | | ✓ | | | | | |
| 48. | Alicia Daugherty – (G2) | PJM | | ✓ | | | | | | | | |
| 49. | G. O'Neal Hamilton-(G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 50. | John E. Howard – (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 51. | Mignon L. Clybur – (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 52. | Phil Riley – (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 53. | Randy Mitchell – (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 54. | C. Robert Moseley– (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 55. | David A. Wright – (G5) | PSC of South Carolina (PSC SC) | | | | | | | | | ✓ | |
| 56. | Chuck Falls (I) (G6) | Salt River Project (SRP) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 57. | Bob Schwermann (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 58. | Brian Jobson (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 59. | Dick Buckingham (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 60. | Dilip Mahendra (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 61. | W. Shannon Black (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 62. | Phil Odonnell (G6) | SMUD- Ops | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 63. | Casey Sprouse (G6) | Sr. Term Marketer | | | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 64. | Maria Denton (G6) | SRP | | | | | | | | | | |
| 65. | Terri M. Kuehneman (G6) | SRP System Operation | | | | | | | | | | |
| 66. | Raquel Agular (G6) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 67. | Ron Belval (G6) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 68. | Jim Haigh - (G3) | WAPA | ✓ | | | | | ✓ | | | | |
| 69. | Raymond Vojdani (G6) | WAPA | | | | | | | | | ✓ | |
| 70. | Mike Wells (G6) | WECC | | | | | | | | | | ✓ |
| 71. | Neal Balu - (G3) | WPS | | | ✓ | | ✓ | ✓ | | | | |
| 72. | Pam Oreschnick - (G3) | XEL | ✓ | | ✓ | | ✓ | ✓ | | | | |

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – APPA
G2 – ISO – RTO Standards Review Committee
G3 – MRO Members
G4 – NPCC CP9 Reliability Standards Working Group
G5 – PSC of South Carolina
G6 - WECC MIC MIS ATC Task Force

## Index to Questions, Comments, and Responses

1. FERC has ordered that the TTC for all posted paths be calculated by using one of three methodologies (1 Rated System Path, 2 Network Response & 3 Flow base). The Rated System Path (RSP) Standard (MOD-029-1) is modeled after the WECC Path Rating Methodology which does not require that all posted paths be rated using the WECC Methodology. There are many posted paths within WECC whose ratings were not calculated using the WECC Path Rating process and would need to be re-rated to conform to the RSP Standard. Should the RSP Standard address this issue? If "Yes" please explain how you believe it should be addressed in the comments area.

**Summary Consideration:** The SDT has opted to adopt the FERC / NAESB approach to "Posted Path" to define the universe of paths addressed in this standard. Further, the SDT has adopted comments suggesting a high level methodology for calculating TTC accompanied by additional delimiters to address a large universe of unique and peripheral circumstances that accompany this approach. Finally, the SDT will adopt a phased in approach when formulating the implementation schedule for this standard to account for the potentially large number of Posted Paths which must be studied or re-studied in order to conform to the new requirements imposed by this standard.

| **Question #1** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | This is the very reason why it is necessary for the TSP to go the TP, PC, RC or TOP (depending on the time horizon of the ATC calculation) which has determined the TTC for reliable operational and planning reasons. Whatever, method the reliability functions have used will be communicated to the TSP and they will post the values and backup information for the calculations. |
| **Response:** This is what is intended. | | | |
| IRC | | ☑ | We do not believe the RSP Standard needs to specifically address WECC Path ratings which were not rated using the WECC Path Rating process. |
| **Response:** The SDT has opted to adopt the existing FERC / NAESB approach of "Posted Path" to define the universe of paths affected by this standard. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC / Charles Yeung. | | | |
| PSCSC | | ☑ | |
| FirstEnergy | | ☑ | |
| WECC MIC MIS ATC TF. | ☑ | | The TTC determinative process for the Rated System Path methodology accurately resides in the MOD-29. The WECC Team suggests that these determinants be fully vetted through the augmented expertise of those being added to the team via the most recent ATC SAR.<br>The WECC Team does not believe it is FERC's intent to require a posting of TTC for each and every path and each and every possible permutation of paths or POR/PODs within a utility's system. It is estimated that this could result in a million plus postings for some utilities; most of these posting would be on paths for which no service has been requested.<br>Rather, FERC has already made it clear that as to posting of ATC and TTC, FERC's intent was stated |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | in its approved definition of "Posted Path." It is the "Posted Path" that requires a posting of ATC and TTC. The WECC Team has the below positive suggestions that will remedy many concerns for MOD-29.<br>Suggested Remedy:<br>18 CFR 37.6, Order 889/RM95-9-000, P. 58-60 and NAESB R-4005 all utilize "Posted Path" as the delineated paths for which ATC and TTC must be posted.<br>At 18 CFR 37.6, the definition for Posted Path states: (control area has been replaced with Balancing Authority to bring the definition in line with the Functional Model)<br>Posted Path means: 1) any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted.<br>(Plagiarized from NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. See also: 18 CFR 37.6;<br>http://a257.g.akamaitech.net/7/257/2422/12feb20041500/edocket.access.gpo.gov/cfr_2004/aprqtr/pdf/18cfr37.5.pdf<br>First, in refining this draft the term "Posted Path" must be adopted in accordance with FERC's intent.<br>The WECC MIC MIS ATC TF Team suggests the following rewrite of R6:<br>R6. For each Posted Path, each Planning Coordinator shall determine TTC using the applicable method below:<br>R6.1. For Posted Paths whose capacity is limited by thermal, voltage or stability limits, TTC shall be the lesser of the thermal, voltage or stability limits as determined by adjusting generation dispatch, area interchange schedules, and Load levels to maximum values (without introducing fictitious facilities or unrealistic values into the system model) to determine the maximum flow that can be simulated on the path while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.<br>• If it is not possible to simulate a flow sufficiently large to reach a reliability-limited TTC, the TTC of the path is equal to the maximum flow simulated and the path is said to be flow limited.<br>• If the TTC determined for a path in one direction is reliability limited and the TTC determined for the same path in the other direction is flow limited, the reliability limited TTC may be used for both directions.<br>R6.2. for Posted Paths whose capacity is limited by contract, TTC shall be set on the Posted Path at the maximum allowable contract capacity, not to exceed the thermal, voltage or stability limits of that Posted Path.<br>R6.3 For Posted Paths whose capacity is jointly owned, TTC shall be set for each separate owner of the Posted Path at the maximum capacity owned by each separate owner.<br>R6.3.1. The Transmission Service Provider shall ensure that for jointly owned paths, the sum of all owners' allocations is equal to the TTC of the path |

<table>
<tr><th colspan="4">Question #1</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>R6.4. For Posted Paths whose capacity has been established for ten years or more (subject to contingency and seasonal adjustment), and that are known to have operated reliably at that established capacity rating, TTC shall be set on the Posted Path at the established, reliable level at which that Posted Path has been operating for at least the previous ten years.<br>R6.5. For new or revised Posted Paths, the Planning Coordinator shall determine if the TTC adversely impacts the path rating or TTC values of existing paths by modeling the flow on the new or revised Posted Path at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level, and if there is an adverse impact:<br>• Limit the TTC for the new or revised path to eliminate the adverse impacts, or<br>• Follow a local or regional procedure for resolving the impact with the affected parties.<br>R6.6. Draft a report to document the steps performed in determining the TTC for the Posted Path.</td></tr>
<tr><td colspan="4">Response: The SDT has accepted those comments with the exception that “R6” as included in the last drafted release should be changed from “maximum values” to “maximum or minimum values.”<br><br>The SDT modified the standard adopting the intent of most of the suggestions identified above.<br>The drafting team adopted the term, ‘Posted Path’ with the proposed definition. The term, ‘Posted Path’ is now used consistently in the set of ATC-related standards.<br>R6 was modified to include the term, ‘Posted Path’ and the requirement was further modified, based on other stakeholder comments, to assign responsibility for determining TTC to the Transmission Operator rather than the Transmission Service Provider.</td></tr>
<tr><td>SRP</td><td>☑</td><td></td><td>SRP supports the comments on this subject submitted by the WECC contingent. Additionally we suggest that the drafting team provide for a "phasing-in" period to allow time for the TSP's who use the Rated System Path Methodology to re-study the TTC for their Posted Paths. This is needed because of the large number of Posted Paths in the west whose TTC was not established by the rigorous methodology stipulated in the R6 of the new standard. If a "phasing-in" period is not appropriately addressed in the standard itself it needs to be provided for somewhere. We suggest an Implementation Plan similar to the CIP Standards. One that requires the Responsible Entities to become Substantially Compliant, Compliant, and then Audibly Compliant within a defined schedule.</td></tr>
<tr><td colspan="4">Response: The SDT concurs that MOD-29 as drafted may expose some entities to compliance risk. The SDT also concurs that a phased in approach is appropriate and necessary and will take that into consideration when the implementation schedule is formulated for this standard.</td></tr>
<tr><td>Entergy</td><td>☑</td><td></td><td>Each Transmission Service Provider should calculated TTC for all posted using the same method for consistency</td></tr>
<tr><td colspan="4">Response: The SDT agrees and believes adoption of the WECC comments will greatly enhance consistency in calculating TTC under this selected methodology.</td></tr>
</table>

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

**Summary Consideration:** Most stakeholders who responded to this comment indicated that the requirements relative to ETC needed improvement. The drafting team modified the requirements by converting the descriptive language into algorithms with a definition for each element in each algorithm:

In the revised standard, the algorithm for firm ETC is: $ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$

**Where:**

**$NL_F$** is the firm capacity reserved to serve peak Native Load forecast commitments for the time period being calculated, to include Native Load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$NITS_F$** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_F$** is the capacity reserved for grandfathered Firm Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service,

**$ROR_F$** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service.

In the revised standard, the algorithm for non-firm ETC is: $ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$

**Where:**

**$NITS_{NF}$** is the non-firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_{NF}$** is the non-firm capacity reserved for grandfathered Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm.

**Question #2**

| Commenter | Yes | No | Comment |
|---|---|---|---|
| WECC MIC MIS ATC TF | | ☑ | The impact of load growth for Network Integration Transmission Service should be included in R12.2. |
| **Response:** The SDT has included the impact of load growth in Network Integration Transmission Service.<br><br>The revised standard includes an algorithm for firm ETC, and in that algorithm, $\mathbf{NITS_F}$ is defined as the firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.<br><br>The revised standard also includes an algorithm for non-firm ETC, and in that algorithm, $\mathbf{NITS_{NF}}$ is defined as the non-firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin. | | | |
| APPA | | ☑ | See my comments on MOD-028 |
| **Response:** The SDT has reviewed the appropriateness of the functions and endeavored to accurately align them with the NERC Functional Model. In all of the revised standards, the responsibility for determining TTC or TFC is assigned to the Transmission Operator, and the responsibility for determining ATC is assigned to the Transmission Service Operator. | | | |
| BPA | | ☑ | The impact of load growth for Network Integration Transmission Service should be included in R12.2. The "five years or longer in duration" language should be removed from R12.5. due to the fact that this element of Order 890 is only to be implemented by a Transmission Service Provider (TSP) once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those existing Customers who have not yet been required to commit to five years of service to retain their roll-over rights. |
| **Response:** The SDT modified the standard in support of these suggestions.<br><br>The revised standard includes an algorithm for firm ETC, and in that algorithm, $\mathbf{NITS_F}$ is defined as the firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.<br><br>The revised standard also includes an algorithm for non-firm ETC, and in that algorithm, $\mathbf{NITS_{NF}}$ is defined as the non-firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.<br>The reference to 'five years or longer' was removed as suggested. | | | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Entergy | | ☑ | We suggest that R12.10 should be a stand alone requirement rather than a sub requirement. R 13 should be a lead requirement with R14 and R 14.1 - R14.5 as sub requirements under R13 requirements. R15 is similar to post back, therefore, it should also be made as a subrequirement under R13. |
| **Response:** R12.10 was revised and instead of a description of how to calculate non-firm ATC, in the revised standard, there is an algorithm that identifies how to calculate non-firm ATC.<br><br>R14 should have been a sub-requirement under R13 – this was a typographical error in the version that was posted for comment. In the revised standard there is an algorithm for the calculation of non-firm ETC that includes what had been R13 through R14.5.<br><br>R15 has been absorbed into the algorithm for determining non-firm ATC in Postbacks. (See R8 in the revised standard.) | | | |
| IESO | | ☑ | We feel that R12.1, R12.2, R12.6 and R14 leave room for double counting for components that shold have been taken care of by TRM and CBM. Further, details to be included for non-firm ATC calculation are missing in R13. |
| **Response:** In the revised standard, the numbering and structure of the standard has been reorganized for clarity.<br><br>The SDT cannot comment on IESO's concern at R13 addressing missing non-firm components as IESO has given the SDT no guidance as to what they believe is missing.<br><br>R12.1, 12.2, 12.6 and R14. all include the as the qualifier "not otherwise included in TRM and CBM" to prevent double counting between either of those standards (MOD-04 and MOD-08) and MOD-29. | | | |
| IRC | | ☑ | We feel that R12.1, R12.2, R12.6 and R14 leave room for double counting for components that shold have been taken care of by TRM and CBM. Further, details to be included non-firm ATC calculation are missing in R13. |
| **Response:** R12.1, 12.2, 12.6 and R14. all include the qualifier "not otherwise included in TRM and CBM" to prevent double counting between either of those standards (MOD-04 and MOD-08) and MOD-29. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| Response: See response to IRC / Charles Yeung. | | | |
| HQTE<br>NPCC | ☑ | | R12.10 should be renumbered R13, R13 should be renumbered R14, R14 should be renumbered R14.1, R14.1 should be renumbered R14.2 (etc.) |
| **Response:** The SDT agrees that the standard as drafted would be clearer if restructured and has reorganized the standard for clarity in the revised standard. | | | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| R12.10 was revised and instead of a description of how to calculate non-firm ATC, in the revised standard, there is an algorithm that identifies how to calculate non-firm ATC.<br><br>R14 should have been a sub-requirement under R13 – this was a typographical error in the version that was posted for comment. In the revised standard there is an algorithm for the calculation of non-firm ETC that includes what had been R13 through R14.5. | | | |
| PSCSC | ☑ | | |

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

**Summary Consideration:** Most stakeholders who responded to this question indicated that reliability would not be diminished if the standard allowed the modeling of fictitious devices. The drafting team removed the parenthetical phrase that had been included in R6.1 which precluded the use of fictitious facilities, but did not make any other revisions to MOD-029 to specifically address the use of fictitious devices**.** The revised standard is silent on this matter – and does not require nor prohibit the use of fictitious modeling elements.

R~~6~~2.1 Except where otherwise specified within MOD-029-1, adjust ~~Determine the reliability limited TTC for a path by adjusting~~ base case generation schedules and Load levels ~~to extreme values (without introducing fictitious facilities into the model)~~ within the updated power flow model to determine the maximum flow (reliability limit) that can be simulated on the Posted P~~p~~ath while at the same time satisfying ~~the~~ all planning for N-0, N-1, and N-2 contingencies as follows: ~~criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria~~.

| **Question #3** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSCSC | | | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| **Response:** The SDT concurs and appreciates your participation. | | | |
| APPA | | | R6 and its Sub-requirements are study methodologies that should not be included in any standard. Requirements of this nature could be interpreted to mean that an entities' future plan that included a resource 6 years from now would be fictitious if in the next planning cycle they determined to remove it. These Standards are written in a Policy format. |
| **Response:** R6 and its sub-requirements outlined the required actions to determine TTC using the rated system path methodology and are necessary to ensure consistency in the determination of TTC.<br><br>The revised standard does not require nor prohibit the usage of fictitious modeling elements. However, FERC has stated that: "We conclude that the NERC process is appropriate as it is open to all industry participants and, therefore, is a suitable arena for establishment of common standards for modeling assumptions." Order 890. P. 298.<br><br>The standards have been rewritten such that they no longer reflect a Policy format as suggested by this commenter. | | | |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| BCTC | | ☑ | The use of artificial input data to increase a TTC limit for scenarios analysis and evaluating the impacts of a proposed generator (which is a fictitious until it has been constructed) would not diminish the liabilty of the system. |
| **Response:** The SDT concurs that in most cases usage of fictitious elements in modeling will not diminish the reliability of the grid for those using the RSP.<br><br>Further, the revised standard does not require nor prohibit the usage of fictitious modeling elements. | | | |
| Entergy | | ☑ | Realistically TTC should be calculated using any controls that can impact flow on the path. By not using all controls such as phase shifting transformers, TTC values are lower than what they can practically be, therefore, potential of underutilizing the transmission system. |
| **Response:** The revised standard does not require nor prohibit the usage of fictitious modeling elements. Note that the revised standard includes more specific requirements concerning modeling, including requiring the modeling of phase shifting transformers. | | | |
| IRC | | ☑ | Reliability would not be diminished by fictitions simulations. This practice is not uncommon in the determination of operating limits and TTCs when available resources are insufficient to stress an interface or transfer level to the "edge". |
| **Response:** The SDT is in agreement with the commenter. The revised standard does not require nor prohibit the usage of fictitious modeling elements. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| FirstEnergy | | ☑ | Permitting the arbitrary introduction of fictitious devices potentially encourages producing the limitation wanted rather than determining the actual limitation. First bullet in R6.1 says the path will be said to be "flow limited", which is a misleading characterization. It really would be "extreme value limited" and should be identified as such. The second bullet in R6.1 seems to be very arbitrary and should be deleted to result in a limit that more accurately reflects the actual ability of the system to transfer power. |
| **Response:** Utilization of fictitious elements in modeling has routinely and reasonably been used by those utilizing the Rated System Path for some time. However, in moving into a mandatory regime the inclusion of this discretionary approach as a mandate may not produce an optimum outcome. Thus, the SDT has opted not to make inclusion or exclusion of fictitious modeling elements a Requirement.<br><br>As to inclusion of the term "flow limited" the term is used widely in the industry, with particular emphasis on those currently using the RSP, that inclusion was warranted Nevertheless, the term flow limited has been deleted from the next version of | | | |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| the standard. | | | |
| IESO | | ☑ | Reliability would not be diminished by incorporating fictitious devices into power flow simulations. This practice is not uncommon in the determination of operating limits and TTCs when available resources are insufficient to stress an interface or transfer level to the "edge" or for other practical modeling reasons. However, entities which use such fictitious devices must ensure that its modeling assumptions are shared with other possible affected entities. |
| **Response:** The SDT is in agreement with the commenter. The revised standard does not require nor prohibit the usage of fictitious modeling elements. The standard does require sharing of assumptions. | | | |
| SRP | | ☑ | The system should be reliable if the TTC in both directions of all paths is reliability limited even if one or more of the reliability limits was found using fictitious devices for stressing the system in order to determine the reliability limit. The flow limit does not represent the capability of the transmission system to reliably transfer power. It does represent the limit of the capability of the system to stress the system which doesn't imply the limit beyond which reliability is in jeopardy. |
| **Response:** The revised standard does not require nor prohibit the usage of fictitious modeling elements. | | | |
| HQTE<br>NPCC | ☑ | ☑ | Real-time system reliability would not be diminished since the actual power transfer is less than the reliability limit. However, long-term reliability could be diminished because posted TTC would be higher than the actual maximum flow. Transmission users could overestimate the path capacity and consequently overestimate the amount of power that can be delivered on this specific path. A path might be voltage limited, not flow limited, and the introduction of a fictitious generator might hide the reliability rating if it supports the voltage on the path in the simulation, but not in "real life". |
| **Response:** The commenters' point is well taken and properly noted. Nevertheless, in moving into a mandatory regime the inclusion of this discretionary approach as a mandate may not produce an optimum outcome. Thus, the SDT has opted not to make inclusion or exclusion of fictitious modeling elements a Requirement. | | | |
| BPA | ☑ | | Allowing the use of artificial input data to increase a TTC limit does not represent the most relevent system conditions to establish a reliabilty limit. |
| **Response:** The revised standard does not require the usage of fictitious modeling elements. | | | |

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

**Summary Consideration:** The stakeholders who responded to this question all indicated that the standard does not need to address the practice of selling the same Non-firm Transmission multiple times. Based on this consensus, the SDT has concluded that the selling of non-firm multiple times should be a NAESB Business Practice and has referred the issue to NAESB. By contrast, "how" non-firm is calculated and accounted for after that calculation is made remains a NERC issue and is included herein.

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | ☑ | The incremental sells of the same non-firm transmission to multiple customers represents a prioritization issue that would best be addressed in a NAESB Business Practice. |
| **Response:** The selling of non-firm multiple times should be a NAESB Business Practice and we will refer that issue to NAESB. | | | |
| APPA | | ☑ | This is a business practice, not reliability |
| **Response:** The selling of non-firm multiple times should be a NAESB Business Practice and we will refer that issue to NAESB. | | | |
| Entergy | | ☑ | Sale of service should not be in scope of this standard, only how TTCs and ATCs are calculated should be included. Accounting for Non-Firm Transmission already sold multiple times should be included in this standard so that accurate ATCs can be calculated and offered for sale to the market place. Sale of Non-Firm Transmission multiple times is a commercial issue and should be addressed by NAESB Business Practice Standard. |
| **Response:** The SDT concurs. | | | |
| FirstEnergy | | ☑ | This is better covered by NAESB as a business practice issue. However, the requirements for loading and unloading the interchange schedules associated with this practice should be included in the NERC Standards to ensure that reliability is not jeopardized. |
| **Response:** The SDT has recommended that "practices" be referred to NAESB. However, the SDT is unclear as to the nuances within the "requirements for loading and unloading the interchange schedules" that FirstEnergy would have the SDT address. FirstEnergy is encouraged to clarify their concerns and make recommendations. | | | |
| HQTE<br>NPCC | | ☑ | As requested in R12.10, non-firm ATC is calculated by reducing TTC by non-firm-ETCs. Depending on time horizon, unscheduled transmission service could be sold multiple-times This is a business issue that should be addressed by NAESB. |
| **Response:** The selling of non-firm multiple times should be a NAESB Business Practice and we will refer that issue to | | | |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| NAESB. | | | |
| IESO<br>IRC | | ☑ | This seems to be a business practice issue. Similar issues are selling non-firm services out of TRMs and/or CBMs which may be recalled when these latter components need to be used for capacity needs or transmission reliability needs. |
| **Response:** The selling of non-firm multiple times should be a NAESB Business Practice and we will refer that issue to NAESB. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See the response to IRC's comments. | | | |
| PSCSC | | | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| **Response:** The SDT concurs and appreciates your participation. | | | |

5. Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

**Summary Consideration:** The SDT has included new language to address how non-firm is treated within the ATC calculation. Here is the algorithm for calculating non-firm ATC as included in the revised standard:

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counter\text{-}schedules_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the Posted Path for that period.

**TTC** is the Total Transfer Capability of the Posted Path for that period.

**$ETC_F$** is the sum of existing non-firm commitments for the Posted Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the Posted Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the Posted Path that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the Posted Path that has not been released for sale as non-firm capacity by the Transmission Service Provider during that period,

**$Postbacks_{NF}$** are adjustments to non-firm Available Transfer Capability due to postbacks for that period, as defined in business practices, and

**$Counter\text{-}schedules_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and described in its Available Transfer Capability Implementation Document.

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSCSC | | | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| **Response:** The SDT concurs and appreciates your participation. | | | |
| NPCC | | ☑ | This is a business issue to be addressed by NAESB. |
| **Response:** The SDT concurs that it has overtones of a business practice; however, in light of FERC's comments in Order 890, P. 262, at this stage of drafting it should be included in the NERC process and not the NAESB process. Here is the directive from Order 890: Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards | | | |

| **Question #5** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage. | | | |
| WECC MIC MIS ATC TF | ☑ | | As drafted the standard is unclear. This team suggests language that better reflects the following: Order 890, P. 351. "The Commission also required transmission providers to make any transfer capability set aside for CBM available on a non-firm basis and to post this availability on OASIS."<br>For clarity, this statement needs to be reconciled with MOD-04-1, R.3.4 stating, "The Transmission Service Provider shall use "zero" as the value for all unscheduled CBM for all non-firm ATC calculations for all methodologies. Order 890. P. 262. |
| **Response:** The SDT clarifies that the "calculation" for CBM should be in MOD-04. However, this MOD-29 Requirement stipulates the "application" of the resulting CBM calculation as one variable within the overall ATC calculation as stipulated in MOD-29. Restated: The CBM variable is calculated in MOD-04; the value is then applied to the overall ATC equation described in MOD-29.<br><br>To address the stated concern, the SDT has Modified the non-firm ATC calculation to include only scheduled CBM. See the algorithm in the Summary Consideration above. | | | |
| APPA | | ☑ | This should be removed, the rules for using CBM should stay in the CBM standards. |
| **Response:** The SDT concurs that it has overtones of a business practice; however, in light of FERC's comments in Order 890, P. 262, at this stage of drafting it should be included in the NERC process and not the NAESB process. Here is the directive from Order 890:<br>Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage. | | | |
| FirstEnergy | | ☑ | MOD-004 should contain all the rules related to CBM. However, R13 and R14 should be renumbered to reflect the appropriate formatting. |
| **Response:** The SDT concurs that it has overtones of a business practice; however, in light of FERC's comments in Order 890, P. 262, at this stage of drafting it should be included in the NERC process and not the NAESB process. Here is the directive from Order 890:<br>Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that | | | |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage.<br><br>R14 should have been a sub-requirement under R13 – this was a typographical error in the version that was posted for comment. In the revised standard there is an algorithm for the calculation of non-firm ETC that includes what had been R13 through R14.5. | | | |
| HQTE | | ☑ | This is a business issue to be addressed by NAESB. |
| **Response:** The SDT concurs that it has overtones of a business practice; however, in light of FERC's comments Order 890, P. 262, at this stage of drafting it should be included in the NERC process and not the NAESB process. Here is the directive from Order 890:<br>Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage. | | | |
| Entergy | ☑ | | For consistency with other methods, excluding CBM from Non-Firm ETC should be included in this standard.. |
| **Response:** .Agree. | | | |
| IESO<br>IRC | ☑ | | It needs to be, but then again it may be a business practice issue. Along this vein, MOD-028 is silent on this and also has no mention of the CBM quantity in the calculation of non-firm ATC. |
| **Response:** The SDT concurs that it has overtones of a business practice; however, in light of FERC's comments Order 890, P. 262, at this stage of drafting it should be included in the NERC process and not the NAESB process. Here is the directive from Order 890:<br>Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage. | | | |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Note that the revised MOD-028 does include an algorithm for the calculation of non-firm ATC and it does require consideration of CBM. Here is the algorithm for determining ATC using the Area Interchange Methodology:<br><br>$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflows_{NF}$<br><br>CBMs is the Capacity benefit margin for the postd path that has been scheduled during that period | | | |
| ERCOT | ☑ | | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC's comments. | | | |

6. Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

**Summary Consideration:** After the posting of the Comment request, the NERC ATC Team met with FERC for a progress report on these standards. It was concluded that greater detail needed to be added to many of the affected standards. The NERC Team further decided that a more uniform structuring across the MOD-28-29-30 standards would better serve the industry. Although it is not anticipated that each of these three standards will be completely uniform in structure, any movement toward that goal will renumber / restructure and reorganize the flow of each affected standard accordingly.

The revised standard does include the following algorithm for the determination of non-firm ATC:

$$ATC_{NF} = TTC - ETC_{F} - ETC_{NF} - CBM_{S} - TRM_{U} + Postbacks_{NF} + Counter\text{-}schedules_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the Posted Path for that period.

**TTC** is the Total Transfer Capability of the Posted Path for that period.

**$ETC_{F}$** is the sum of existing non-firm commitments for the Posted Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the Posted Path during that period.

**$CBM_{S}$** is the Capacity Benefit Margin for the Posted Path that has been scheduled during that period.

**$TRM_{U}$** is the Transmission Reliability Margin for the Posted Path that has not been released for sale as non-firm capacity by the Transmission Service Provider during that period,

**$Postbacks_{NF}$** are adjustments to non-firm Available Transfer Capability due to postbacks for that period, as defined in business practices, and

**$Counter\text{-}schedules_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and described in its Available Transfer Capability Implementation Document.

This shall serve as a single response to all comments offered in response to this question.

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSCSC | | | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| NPCC | | ☑ | R14 is for planning and operating horizons and R15 is only for operating horizon |
| APPA | | ☑ | These are confusing and should be removed. R14 is written in a manner it is impossible to determine which Reliability function is responsible to meet the standard. In addition, any reference to non-firm |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | ATC should be in MOD-001, not spread out through several standards. |
| HQTE | | ☑ | R14 is for planning and operating horizons and R15 is only for operating horizon |
| WECC MIC MIS ATC TF | ☑ | | Merely combining these may not be sufficient to make clear what the TSP is supposed to do. R14 should, at minimum, be a subset of R13, lest there be no responsible party. Adding R15 as a subset of R13 would be appropriate.<br>Some in WECC assert that all "non-firm" is a business practice to be determined by NAESB. Others believe "non-firm" should be addressed in MOD-01 - not here. |
| Entergy | ☑ | | Please see comments to Question 2 above |
| ERCOT | ☑ | | See IRC comments submitted by Charles Yeung. |
| FirstEnergy | ☑ | | They should be combined to strengthen the reader's understanding of the material. |
| IESO | ☑ | | R14 and R15 could be combined. However, in R15, we do not understand what would be the items that are "the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC,.." |
| IRC | ☑ | | R14 and R15 may be combined. However, in R15, we do not understand what would be the items that are "the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC,.." |

7. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

**Summary Consideration:** The SDT has engaged NERC and the Functional Model team in an effort to add additional Applicable entities for insertion into the standard(s). That dialogue is ongoing. The SDT has requested a new role of "Operations Planner" utilizing the Functional Model. In the interim, the term Transmission Operator has supplanted Operations Planner. The Reliability Coordinator and Planning Coordinator were removed as 'applicable entities' in the revised standard. In the set of revised standards, the Transmission Operator has been assigned responsibility for determining TTC and TFC and the Transmission Service Provider has been assigned responsibility for determining ATC.

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | ☑ | Although the "Applicability" section states it is applicatable to Relaibility Coordinators, there is nothing in the draft that applies to an RC. |
| **Response:** References to the Reliability Coordinator have been removed. | | | |
| APPA | | ☑ | See Comments on MOD-029 |
| **Response:** We do not find your additional comments on MOD-29. | | | |
| BCTC | | ☑ | ATC related standards should be applicable only to entities who have the obligation to provide non-discrimintory transmission service, that is the Transmission Service Providers. |
| **Response:** The SDT believes this standard applies to entities other than the TSP. For example, the TSP is required to post assorted data. If there is no requirement for the providing entity to supply the data, the TSP cannot be obligated to post that which other entities will not provide. Thus, additional entities are implicated.<br>In the revised set of standards (MOD-028, MOD-029, MO-030), the drafting team assigned the Transmission Operator the responsibility for determining TTC or TFC and assigned the Transmission Service Provider with the responsibility for determining ATC. The requirements for the Planning Coordinator and Reliability Coordinator were removed from the revised standard. | | | |
| BPA | | ☑ | "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority. |
| **Response:** According to members of the Functional Model Work Group, the Planning Coordinator and the Planning Authority are essentially the same. The drafting team will post a definition of 'Planning Coordinator' so that it can be formally entered into the NERC Glossary of Terms Used in Reliability Standards. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** See response to IRC. | | | |
| IESO | | ☑ | Unlike the other MOD standards, this standard more appropriately reflect the role of the PC and RC in the determination of transfer capabilities, not ATC. However, the applicability section gives rise to unclear responsibilities between TSP and the PC/RC in that both calculate transfer capabilities of the "paths". We feel that the PC and RC are responsible for calculating the total path capability, whereas the TSP is responsible for calculating the available path capability. This distinction needs to applied to all the MOD standards. |
| **Response:** The SDT concurs that the RC is not responsible for calculating TTC. Please see the Summary Consideration for this question. In the revised set of standards (MOD-028, MOD-029, MO-030), the drafting team assigned the Transmission Operator the responsibility for determining TTC or TFC and assigned the Transmission Service Provider with the responsibility for determining ATC. The requirements for the Planning Coordinator and Reliability Coordinator were removed from the revised standard. | | | |
| IRC | | ☑ | Unlike the other MOD standards, this standard more appropriately reflect the role of the PC and RC the determination of transfer capabilities, not ATC. However, the applicability section gives rise to unclear responsibilities between TSP and the PC/RC in that both calculate transfer capabilities of the "paths". We feel that the PC and RC are responsible for calculating the total path capability, whereas the TSP is responsible for calculating the available path capability. |
| **Response:** See comments at the summary header of this section. In the revised set of standards (MOD-028, MOD-029, MO-030), the drafting team assigned the Transmission Operator the responsibility for determining TTC or TFC and assigned the Transmission Service Provider with the responsibility for determining ATC. The requirements for the Planning Coordinator and Reliability Coordinator were removed from the revised standard. | | | |
| NPCC<br>HQTE | ☑ | ☑ | MOD-029 includes applicability to Reliability Coordinator, but there is no reference in the details of the standard to the RC. A role should be defined, or RC should be removed from the Applicability section. All MOD standards should be consistent in their description of the roles for providing input and calculating ATC. |
| **Response:** References to the RC have been removed. In the revised set of standards (MOD-028, MOD-029, MO-030), the drafting team assigned the Transmission Operator the responsibility for determining TTC or TFC and assigned the Transmission Service Provider with the responsibility for determining ATC. | | | |
| FirstEnergy | ☑ | | MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once, eliminate duplication, and simplify the applicability sections of MOD-028, 029, and 030. |
| **Response:** The SDT discussed this issue in depth and asked stakeholders for feedback on this issue – most stakeholders | | | |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| supported separating the standards – as this adds clarity by providing more details on each of the the diverse metholdogies addressed therein. | | | |
| Entergy | ☑ | | |
| PSCSC | ☑ | | |

8. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

**Summary Consideration:** The SDT has adequately addressed the directives identified in the FERC Orders 890 and 693 related to Rated System Path**.** To assist stakeholders, when the revised standards are posted, the drafting team will post a table that shows each of the directives and identifies the standard in which the directive is addressed.

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings.<br>FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC. |
| **Response:** After clarification from FERC and in depth discussions on this issue, the SDT is proposing to retire FAC-12 and 13 and has imported all substantive requirements into the appropriate MOD-28-29-30. | | | |
| IESO<br>IRC | ☑ | ☑ | It appears that the SDT has addressed all of the FERC directives. However, in view of the many comments provided to this and the other related MOD standards, and hence substantive changes are expected, we see the need to revisit this subject again when revised standards are posted. |
| **Response:** To assist stakeholders, when the revised standards are posted, the drafting team will post a table that shows each of the directives and identifies the standard in which the directive is addressed. | | | |
| ERCOT | ☑ | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC. | | | |
| FirstEnergy | | ☑ | |
| Entergy | ☑ | | |

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| FirstEnergy | ☑ | | |
| PSCSC | ☑ | | |

9. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

**Summary Consideration:** In general the industry has identified no regulatory conflicts. However, the industry does remain concerned that some if not all of these standards may not apply to them based on their specific circumstance. Assigning liability is outside the scope of this SDT. Where an entity believes they are exempt for regional differences the regional variance process is available.

| Question #9 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | | See question 8 above |
| **Response:** See response above to APPA on Question 8. | | | |
| HQTE | | | We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets. |
| **Response:** The SDT concurs and suggests that the narratives required in the ATCID and the OATT Attachment C should address HQTE's concerns; however, HQTE has raised enforcement concerns that are outside the scope of the SDT. | | | |
| IESO<br>IRC | | ☑ | No, but please note that some markets do not offer physical transmission services and hence some of the requirements in this standard do not apply to these entities. |
| **Response:** The SDT concurs. | | | |
| NPCC | | | We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets. |
| **Response:** The SDT concurs. | | | |
| PSCSC | | ☑ | |
| WECC MIC MIS ATC TF | | ☑ | |
| BCTC | | ☑ | |
| Entergy | | ☑ | |
| ERCOT | ☑ | | ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through |

| Question #9 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area and there has been no reservation of transmission capacity in ERCOT.<br><br>Available Transfer Capability is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. The ERCOT Interconnection has already moved “beyond” ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therfore both ERCOT and SPP are notified when the DC Tie capability is reduced.<br><br>Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.<br><br>In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.<br><br>In the current and future ERCOT market design the method of calculating ATC, TTC and the use of |

| Question #9 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | CBM and TRM are not applicable to the ERCOT Interconnection. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance. |
| **Response:** The drafting team believes the Applicable Entities delineated in the Applicability section of MOD-29 would already exclude ERCOT from compliance "so long as" ERCOT does not use the Rated System Path Methodology.<br><br>While the SDT can establish Applicable Entities, it cannot determine liability on ERCOT's part for failure to adhere to a Standard. Assigning liability is outside the scope of this SDT. FERC has made it clear that where an entity believes they are exempt for regional differences the regional variance process is available. | | | |

10. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-029-1.

**Summary Consideration: Varied.**

| Question #10 | |
|---|---|
| **Commenter** | **Comment** |
| WECC MIC MIS ATC TF | A. The current "R14." should be numbered as "R13.1." and this will have an impact on all subsequent requirements.<br>B. In the "Applicability" section, the term "Available Transfer Capability Implementation Document" is used as a defined term. The term is used in MOD-01 R3. At minimum the ATCID either needs to be defined or a reference to the MOD-01 must be inserted for cross reference into each Standard in which it appears.<br>C. R1. Change the determinant from "the" to "a" in the parenthetical.<br>D. I n the "Applicability" section, either "Planning Coordinator" needs to be defined and imported into the NERC Glossary or a more appropriate entity such as "Planning Authority" may be in order.agreed<br>E. R6. The term "extreme" is overly vague. This Team suggests replacement with the words "maximum or minimum".<br>F. R7-R8. Change "posted path" to "Posted Path".<br>As with MOD-08, Posted Path should be defined as:<br>Posted Path<br>Posted Path means: 1) any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.<br><br>G. The term "postbacks" appeared in Order 890, P. 212. "Therefore, we direct public utilities, working through NERC, to modify related ATC standards by implementing the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows." Since the term is not defined and whereas FERC did not specify exactly what it is, the NERC Team should clarify what FERC meant by the term before inserting it into the calculation process.<br>H. R6. Everytime the word "path" is used it should be replaced with "POSTED PATH." agreed<br>I. To assist the industry in determining which of the three methodologies is best suited for the TSP's needs, it is suggested that a statement be inserted into the "Purpose" section of MOD-28 / 29 / 30 stating its intended use.<br>E.g. MOD-28 was modeled on the ATC process of much of the Eastern Interconnect. |

| Question #10 | |
|---|---|
| **Commenter** | **Comment** |
| | MOD-29 was modeled on the ATC process of much of the WECC Interconnet.<br>J. R12.5 Delete "five years or longer in duration." |
| **Response:**<br><br>A. Agreed. R14 should have been numbered as R13.1 – the content of R13 has been converted into an algorithm in the revised standard.<br>B. Agreed. The drafting team added a definition for Available Transfer Capability Implementation Document. The term is introduced in MOD-001 and is defined in the revised version of MOD-001.<br>C. Agreed. This change is reflected in the revised standard – see R2,6.<br>D. Agreed. The Planning Coordinator is the same entity as the Planning Authority – just a new name introduced in Version 3 of the Functional Model. The drafting team will post a definition for the Planning Coordinator. Note that the RC has been supplanted by Transmission Operator in this standard.<br>E. R6 was revised and now requires the determination of the 'maximum' flow in support of your suggestion.<br>F. Agreed. The drafting team adopted the defined term, 'Posted Path' and has used this in the revised set of ATC-related standards.<br>G. Agreed. We have asked NAESB to define this term, as we believe that Post Backs are commercial in nature.<br>H. Agreed. The drafting team adopted the defined term, 'Posted Path' and has used this in the revised set of ATC-related standards.<br>I. Agreed. All of the Purpose statements were modified to include a reference to the associated methodology as proposed.<br>J. Agreed. The reference to 'five years or longer in duration' was removed from what had been R23.5. | |
| APPA | The Standard is written much like a Policy and it cannot be determined who is responsible for the different calculations of the components of the ATC. The Standard does not provide the Compliance Monitor or the TSP who calculates the Hourly. Daily, and Monthly ATCs with the necessary requirements to know what is necessary to be compliant. |
| **Response:** We have modified the standard to address this concern. | |
| BCTC | Requirements R3, R4, R5, and R6 are similar to what we are required to do under FAC-010-1. Similarity is good, but in this case there are areas of duplication and inconsistency. For example:<br>1. FAC-010-1 requires Planning Authorities to have an SOL Methodology that reflects the requirements similar to R3 and R4. Is NERC proposing that they will audit on having an SOL Methodology consistent with FAC-010 and then audit on determining TTCs consistent with MOD-029.<br>What happens if our SOL Methodology differs from MOD-029?<br>It seems that the TTC standard should only require to determine TTCs based on SOLs, which is what FAC-012 requires. |

| **Question #10** | |
|---|---|
| **Commenter** | **Comment** |
| | 2. Requirement R5 requires the use of assumptions consistent with expansion planning analysis. It is unclear what this means or how this would be audited, except by looking at SOL Methodology, unless we are also required to document our assumptions for MOD-029. This would be duplicative of our SOL Methodology.<br><br>3. Requirement R6 is not acceptable because it limits what we can consider in determining TTCs. R6.1, which references TPL-001 and TPL-002, is somewhat consistent with FAC-010. However, the reference should be to FAC-010, System Operating Limits, not the transmission planning standards. TPL-001 and TPL-002 do not have Western Interconnection differences, and TTCs need to allow for consideration of regional differences. Furthermore, we have to ask what is the purpose of BCTC having an SOL Methodology (FAC-010) and determining SOLs according to this Methodology (FAC-014), if MOD-029 provides criteria for determining TTCs. This is setting us up for a reliablity vs. commercial capacity conflict.<br><br>4. The second bullet under R6.1 is not acceptable. If a path is flow limited to less than "the reliability limit", how can we provide TTC up to the reliability limit. Firstly, we cannot calculate a reliability limit for anything higher than what will flow on the path (without using fictitious devices). Secondly, how can a customer use it?<br><br>5. Our suggestion to NERC would be to follow the structure layed out in the FAC series. Transmission Owners determine Facility Ratings according to FAC-008 and 009. Based on these Facility Ratings and other factors, Planning Coordinators, Reliability Coordinators, Transmission Planners determine SOLs according to FAC-010, 011,and -014. Based on these SOLs, PCs, RCs, and TSPs determine TTC, etc. according to the applicable NERC standard.<br><br>The above comments are also applicable to MOD-28-1 and MOD 30-1. |

**Response:**

(1) BCTCs suggestion is well received, and the drafting team added the following requirement to the revised standard to address this concern.

- R4. Each Transmission Operator shall establish the TTC as the lesser of the TTC calculated in MOD-029-1 or any System Operating Limit for that Posted Path.)

The SDT concurs that, much like FAC-10, FAC-11 (and FAC-12) as proposed for FERC approval FERC (), language needs to be added to MOD-29 stating that TTC shall not exceed the SOL. Restated, the TTC predicated on the TPL approach shall not exceed the SOL as determined in the FACs. "The TTCs shall respect all applicable System Operating Limits."

As FERC has pointed out, ATC is both a commercial as well as a reliability issue. A series of checks and balances is created by predicating the MOD-29 TTC on the proposed TPL method tempered by the SOLs as suggested by BCTC. By predicating the TTC on the proposed TPL methodology, a more robust TTC figure is calculated thereby prompting full utilization of the grid. By contrast, when that same TTC value is filtered through the SOL value, as BCTC suggests, system reliability keeps TTC in check and prompts over utilization. In no way does establishment of TTC via the proposed TPL-001 and TPL-002 methodology infringe on BCTC's need nor obligation to continue to calcuate an SOL. Both are needed.

| Question #10 | |
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| **Commenter** | **Comment** |
| As for the substantive requirements of FAC-12 and FAC-13, the SDT is importing these into the ATC-related MOD standards and proposing 12 and 13 be retired.<br><br>B. (2) R5 was inserted in the standard to satisfy a directive in Order 890 (P.292). The SDT has moved R5 into MOD-001. R8 was added to the revised MOD-001 to ensure that, whatever method is used to calculate TTC, TFC or ATC, the assumptions used must be consistent with those used in any associated operations or planning studies for the time period being studied.<br><br>C. (3) MOD-28, 29 and 30 were not specificially designed to include all features of the ATC calcuation for any specific RRO. Although the TPL approach proposed in the first draft of proposed revisions to MOD-029, did not directly incorporate all of WECC's regional differences, by using TPL-001 and TPL-002, the standard mimiced WECC's Path Rating approach at a high level thus allowing non-WECC entities a proper umbrella for inclusion should they decide to select the RSP.<br>The drafting team modified R6 so that the specific reference to the TPL standards (". . .while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.") was replaced with more generic language to achieve the same purpose (". . .while at the same time satisfying all planning criteria for N-0, N-1, and N-2 contingencies as follows:")<br><br>D. (4) The SDT modified the second bullet under R6 in support of your suggestion – in the revised standard, this is R2.2:<br>R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction.<br><br>E. (5) The SDT reviewed the Applicability section in light of the NERC Functional Model and has assigned Applicable entities based on the Model and the Team's best understanding of the activities assigned. In the revised set of standards, the Transmission Operator is assigned responsibility for determining TTC and the Transmission Service Provider is assigned responsibility for determining ATC. | |
| BPA | The ATC MODs (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide narrative descriptions of these methodologies.<br>The Applicability section 4.1. through 4.3. and R1., R4. through R11., R15., and R16. should be clarified that ATC need only be calculated and posted for Posted Paths, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. agreed<br>R2. and R9. -- Making TTC study reports publicly available would present system security concerns due to the fact that such studies will identify the most limiting contingencies. Identifying the most critical contingencies publicly could make them a target and thus reduce system reliability. This information should only be shared with those |

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| **Commenter** | **Comment** |
| | entities demonstrably impacted by such limiting contingencies.<br>R12.7. and R14.5. -- Please define the term "Post-back".<br>The current "R14." should be numbered as "R13.1." and this will have an impact on all subsequent requirements. |
| **Response:**<br><br>The purpose statement of MOD-028, MOD-029 and MOD-030 was revised to include a description of the associated methodology – and each of the methodologies has been defined. The Reliability Standards Development Procedure does not have a place, other than in definitions and reference documents, for inclusion of narrative descriptions.<br><br>"Posted Path" concept has been adopted and is used extensively in the set of revised standards.<br><br>As to the confidentiality concerns, the drafting team removed all requirements in the standards that used the term, 'make publicly available' - NAESB will be addressing any public release of information.<br><br>As to "post back", the SDT agrees. NAESB is developing a definition for this term.<br><br>As to R14, the SDT concurs that The version of the standard posted for comment was not numbered correctly. In the revised standard, the content of R13 has been placed into an algorithm and there are no sub-requirements. | |
| Entergy | R1- it is not clear which "report drafted for a TTC study" is referred to and what study is conducted.<br><br>R3 - "critical modeling details" is vague and should be explained.<br><br>R3 and R4 - it appears that only one model is used for calculation of TTC for all paths and time horizons, if yes, it appears unrealistic, if no, model should be made plural.<br>R4 - are Long Term Firm Transmission Service Reservations included in base cases? If so, these should be included as subrequirement under R4.<br><br>R4 - R4 should include planned and unplanned outages, if included in the base case.<br><br>R6.2 refers to path rating - is it same as TTC of that path, if so, only TTC based on path rating should be used.<br><br>R6.2, it is not clear what is "revised path".<br><br>R6.2 second bullet - are local or regional procedures approved by any entity? These should be included in the data to be made publicly available and included in R9. |

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| **Commenter** | **Comment** |
| | R8 - it appears like each Planning Coordinator determine TTC for all posted path of Transmission Service Provider. "value" should be made plural. It is not clear how frequently TTC values are calculated or updated. |
| **Response:**<br><br>R1 – SDT agrees. This has been corrected in the revised standard by rearranging the sequence of requirements so that all steps associated with determining TTC are in a single requirement. Putting together a report that includes the TTC and its associated assumptions, etc is now part of R2. The new sub-requirement refers to the report as a "study report," providing detail as to what goes in the study report<br>R3 – SDT agrees. This requirement has been clarified by the following rewording and is R1 in the revised standard:<br><br>When calculating TTC for Posted Paths, the Transmission Operator shall use a Transmission model the meets the following criteria:<br><br>R3-R4 – There is a separate study for each path for each time period using a separate model if deemed appropriate. The WECC coordinated base cases are usually the seed cases for building these models. Although normally the same model is not used to conduct all TTC studies since R3 & R4 reference model in a generic sense the SDT feels that using the word "model" in the singular form is appropriate.<br>R4 - Initially, they are included but since generation and load can be adjusted to maximize stress on the path of interest they are not very relevant. TTC studies are case specific or outage specific. A special study will be run if the TTC for a particular outage condition is of interest.<br>R6.2 – Path Rating and TTC are the same thing in WECC vernacular. You are correct that we should be using the word "TTC" instead of "path rating" for this section of the standard to avoid confusion, and we've modified the standard in support of this suggestion. See the use of the acronym, TTC instead of 'path rating' in the revised standard's Requirement 2.<br>R6.2 "Revised path" is a Posted Path that has been revised. Note that the requirement to make the study results publicly available has been deleted as all posting requirements are being addressed by NAESB as business practices.<br>R8 - The SDT believes the correct role for this task is actually the "Operations Planner," a role that does not exist in the functional model at this time. The SDT has requested a new role of "Operations Planner" utilizing the Functional Model. In the interim, the term Transmission Operator has supplanted Operations Planner.<br><br>TTC will be calculated as necessary to support the requirements for ATC specified in MOD-001. | |
| FirstEnergy | R6.2 demonstrates the essential difference with Network Response ATC calculations.<br><br>R11 should be revised to eliminate the subtraction of a portion of TRM from TTC to calculate ATC since this has |

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| **Commenter** | **Comment** |
| | already occurred in R6.2 where parallel path impacts are covered. |
| **Response:**<br>The drafting team modified the standard so that it includes algorithms for the determination of ETC and ATC. The revised standard includes the following algorithm for the determination of firm ATC, and it does subtract TRM from TTC as proposed:<br>$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + Counter\text{-}schedules_F$ | |
| NPCC<br>HQTE | For Clarification:<br>R6.1 Regional criteria (NPCC) are not all included in TPL-001 and TPL002 for contingencies in Table 1, category B…There should be acknowledgement that there can be regional differences in the application of planning criteria that may extend beyond Category B contingencies in determination of TTC.<br>R.12.10 (re-numbered to R13) : Note that the TRM allocated to the path for non-firm ATC may be less than the TRM for firm ATC.<br>R12.10 (renumbered to R13): As it is not specified , we understand that the TSP is free to calculate the ATC by reducing the TTC by reserved or by scheduled transmission services depending on the time horizon.<br>R11: Use of the word "impact" in the formula for ATC introduces confusion. Can R11 be written in formula format like the Version Zero standards?<br>R11.4 Use of the word "impact" is redundant. |
| **Response:**<br>R6.1 – The drafting team modified R6.1 so that the specific reference to the TPL standards (“. . .while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.”) was replaced with more generic language to achieve the same purpose (“. . .while at the same time satisfying all planning criteria for N-0, N-1, and N-2 contingencies as follows:”)<br><br>R.12.10 was converted into a requirement to use an algorithm to determine non-firm ETC – here is the algorithm:<br><br>R6. When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for a Posted Path the Transmission Service Provider shall use the following algorithm:<br>$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$<br>**Where:** | |

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| **Commenter** | **Comment** |
| | **$NITS_{NF}$** is the non-firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.<br><br>**$GF_{NF}$** is the non-firm capacity reserved for grandfathered Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.<br><br>**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.<br><br>**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm.<br><br>R.11 – Agreed. The term "impact" has been removed and the descriptive language was converted into an algorithm similar to the one above for R12.10. |
| IESO | Please see our comments on the supplementary SAR will be addressed in response to sup sar |
| **Response:** Please see the team's response to the comments on the supplementary SAR. | |
| IRC | Please see our comments on the supplementary SAR. will be addressed in response to sup sar |
| **Response:** Please see the team's response to the comments on the supplementary SAR. | |
| ERCOT | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC comments. | |
| MEC | Our footprint does not include facilities in the WECC, therefore, I do not answer all the questions on the MOD-029-1 but provides the following comments:<br><br>1. The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The purpose in MOD-028-1 be revised to replace "uniform" with "transparent".<br><br>2. The Functional Entity as provided in A.4. should not be qualified, for example, A.4. should just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider.<br><br>3. For R1, R3, R4, R5, R6, R7, and R8, the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as |

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| **Commenter** | **Comment** |
| | appropriate", do these requirements in the standard.<br><br>4. R6.1 refers to only certain NERC planning criteria, when the TTC must be based upon the appropriate planning criteria whatever that is. The references to planning criteria should be expanded to include all applicable planning criteria, including NERC, regional, subregional, Transmission Owner, etc.<br><br>5. R2, R9, R16 and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration.<br><br>6. R12 should be revised to indicate that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropriate level of " the following inputs.<br><br>7. R14 should be renumbered R13.1 and R14.1 through R14.5 should be renumbered R13.2 through R13.6. R15 and R16 should be renumber R14 and R15.<br><br>8. Existing transmission commitments should be listed without capital letters or else it needs to be defined for the NERC Glossary. |

**Response:**
(1) Agreed; the drafting team modified the purpose statements in MOD-28, 29, 30 to include a reference to the associated methodology and to clarify that the purpose was to increase consistency and transparency.
(2) The qualifiers used in the Applicability section clarify which entities are being held responsible for the various requirements. The qualifying language is included in support of the Reliability Standards Development Procedure.
(3) The SDT modified the Applicable entities to more closely align with the Functional Model – the Transmission Operator has been assigned responsibility for determining TTC or TFC and the Transmission Service Provider has been assigned responsibility for determining ATC. This change was made in MOD-028, MOD-029 and MOD-030. The SDT disagrees that MOD-29 presumes the existence of an RTO.
(4) The drafting team modified R6.1 so that the specific reference to the TPL standards (". . .while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.") was replaced with more generic language to achieve the same purpose (". . .while at the same time satisfying all planning criteria for N-0, N-1, and N-2 contingencies as follows:")
(5) The SDT agrees; however, R2, R9 and R16 have been removed from the revised standard as all posting issues are being addressed by NAESB in business practices.. The SDT will advise NAESB of your comments.
(6) R12 was revised now states:

When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for a Posted Path, the

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| **Commenter** | **Comment** |
| | Transmission Service Provider shall use the following algorithm:<br><br>(7) The SDT concurs that renumbering / restructuring would have added clarity to the standard. The format of the revised standard is quite different, and the requirements for calculation of ETC and ATC include specific algorithms and don't have any sub-requriements.<br>(8) The SDT agrees. A defintion for ETC has been included with the revised version of MOD-001. |
| MRO | The MRO footprint does not include facilities in the WECC, therefore, the MRO does not answer all the questions on the MOD-029-1 but provides the following comments:<br><br>1. The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The MRO recommends that the purpose in MOD-028-1 be revised to replace "uniform" with "transparent"<br><br>2. The MRO believes that the Functional Entity as provided in A.4. should not be qualified, for example, the MRO recommends that A.4. just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider.<br><br>3. The MRO believes that for R1, R3, R4, R5, R6, R7, and R8, the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard.<br><br>4. R6.1 refers to only certain NERC planning criteria, when the TTC must be based upon the appropriate planning criteria whatever that is. The references to planning criteria should be expanded to include all applicable planning criteria, including NERC, regional, subregional, Transmission Owner, etc.<br><br>5. R2, R9, R16 and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration.<br><br>6. R12 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropriate level of " the following inputs.<br><br>7. R14 should be renumbered R13.1 and R14.1 through R14.5 should be renumbered R13.2 through R13.6. R15 and R16 should be renumber R14 and R15.<br><br>8. Existing transmission commitments should be listed without capital letters or else it needs to be defined for the |

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| **Commenter** | **Comment** |
| | NERC Glossary. |

**Response:** (1) Agreed; the drafting team modified the purpose statements in MOD-28, 29, 30 to include a reference to the associated methodology and to clarify that the purpose was to increase consistency and transparency.
(2) The qualifiers used in the Applicability section clarify which entities are being held responsible for the various requirements. The qualifying language is included in support of the Reliability Standards Development Procedure.
(3) The SDT modified the Applicable entities to more closely align with the Functional Model – the Transmission Operator has been assigned responsibility for determining TTC or TFC and the Transmission Service Provider has been assigned responsibility for determining ATC. This change was made in MOD-028, MOD-029 and MOD-030. The SDT disagrees that MOD-29 presumes the existence of an RTO.
(4) The drafting team modified R6.1 so that the specific reference to the TPL standards (". . .while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.") was replaced with more generic language to achieve the same purpose (". . .while at the same time satisfying all planning criteria for N-0, N-1, and N-2 contingencies as follows:")
(5) The SDT agrees; however, R2, R9 and R16 have been removed from the revised standard as all posting issues are being addressed by NAESB in business practices.. The SDT will advise NAESB of your comments.
(6) R12 was revised now states:

> When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for a Posted Path, the Transmission Service Provider shall use the following algorithm:

(7) The SDT concurs that renumbering / restructuring would have added clarity to the standard. The format of the revised standard is quite different, and the requirements for calculation of ETC and ATC include specific algorithms and don't have any sub-requriements.
(8) The SDT agrees. A defintion for ETC has been included with the revised version of MOD-001.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a standard drafting team on March 17, 2006.

**Description of Current Draft:**

This is the first draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR with consideration of applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Respond to comments. | TBD |
| 2. Post revised standard for stakeholder comment. | TBD |
| 3. Respond to comments. | TBD |
| 4. Post for 30-day pre-ballot review. | TBD |
| 5. First ballot of standard. | TBD |
| 6. Respond to comments. | TBD |
| 7. Recirculation ballot. | TBD |
| 8. 30-day posting before board adoption. | TBD |
| 9. Board adoption. | TBD |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title:** **Network Response Available Transfer Capability**

2. **Number:** MOD-028-1

3. **Purpose:** To promote the consistent and uniform application and documentation of Available Transfer Capability (ATC) calculations performed using the Network Response method for reliable system operations.

4. **Applicability:**

   **4.1.** Each Planning Coordinator that uses the Network Response method to calculate ATCs for paths identified in an Available Transfer Capability Implementation Document.

   **4.2.** Each Reliability Coordinator that uses the Network Response method to calculate ATCs for paths identified in an Available Transfer Capability Implementation Document.

   **4.3.** Each Transmission Service Provider that uses the Network Response method to calculate ATCs for paths identified in an Available Transfer Capability Implementation Document.

5. **Proposed Effective Date:** To be determined.

## B. Requirements

**R1.** Each Planning Coordinator and Reliability Coordinator shall provide its Transmission Service Provider with a list of the Contingencies and assumptions it uses in determining Transfer Capabilities for the paths under the Transmission Service Provider's tariff.

**R2.** The Transmission Service Provider shall make the Contingencies and assumptions provided by the Planning Coordinator or Reliability Coordinator publicly available.

**R3.** The Transmission Service Provider shall make publicly available a list of its Point-of-Receipt (POR) to Point-of-Delivery (POD) Paths that includes, at a minimum, all interfaces between Balancing Authorities within or adjacent to the Transmission Service Provider's area.

**R4.** Each Planning Coordinator and Reliability Coordinator shall ensure that the Total Transfer Capability (TTC) for each of its Transmission Service Provider's POR to POD Paths is calculated and up-to-date for use within the Transfer Capability time horizons specified in MOD-001 R2.

**R5.** Prior to calculating TTC, each Planning Coordinator and Reliability Coordinator shall update the following components of the base case power flow model it uses to calculate TTC for the time horizon being studied:

**R5.1.** Anticipated transmission system configuration.

**R5.2.** Facility Ratings.

**R5.3.** Load forecast.

**R5.4.** Transmission system Elements scheduled to be taken out of or returned to service.

**R5.5.** Generation resources scheduled to be taken out of or returned to service.

**R5.6.** Unplanned transmission system Element outages.

**R5.7.** Unplanned generation resource outages.

**R5.8.** Typical generation dispatch order or the generation participation factors of all units on an affected Balancing Authority basis.

**R5.9.** Special Protection System models.

**R5.10.** Appropriate Firm Transmission Service Reservations.

**R5.11.** The data from R5.1 through R5.10 provided by adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.** Each Planning Coordinator and Reliability Coordinator shall follow these steps in determining the TTC for each path specified:

**R6.1.** Study the impact of increasing the transfer(s) between the POR and POD by adjusting Loads or generation to reach a reliability limit (first contingency incremental transfer capability) such that the system can withstand any single Contingency and achieve the following results:

**R6.1.1.** Transient, dynamic or voltage instability shall not occur.

**R6.1.2.** All facilities shall be within their associated Facility ratings.

**R6.1.3.** Cascading Outages or uncontrolled separation shall not occur.

**R6.2.** Add into the first contingency incremental transfer capability, all impacts of Firm Transmission Service Reservations that were included in the study model to obtain the 'first contingency TTC'.

**R6.3.** Use (as the TTC) the lesser of the value of the 'first contingency TTC' or the sum of Facility Ratings of all interfaces between the POR and POD.

**R7.** The Planning Coordinator and Reliability Coordinator shall each provide its Transmission Service Provider with the TTC for each of the specified paths.

**R8.** The Transmission Service Provider shall make publicly available the TTCs provided by its Planning Coordinator and Reliability Coordinator(s) upon their being made available to the Transmission Service Provider.

**R9.** The Transmission Service Provider shall calculate Available Transfer Capability (ATC) for the time horizons specified in MOD-001 R2 according to the ATC calculation schedule specified in MOD-001 R5.

**R10.** The Transmission Service Provider shall calculate firm ATC by reducing the TTC by the sum of the firm Existing Transmission Commitments (ETCs), the Capacity Benefit Margin (CBM), and the Transmission Reliability Margin (TRM) allocated to the path.

**R11.** The Transmission Service Provider shall determine the impact of firm ETCs based on the following inputs:

**R11.1.** The transmission capability utilized in serving Native Load commitments, to include Native Load growth, load forecast error and losses not otherwise included in TRM or CBM.

**R11.2.** The impact of Firm Network Integration Transmission Service serving Load, to include load forecast error and losses not otherwise included in TRM or CBM.

**R11.3.** The impact of grandfathered Firm Transmission Service Agreements and bundled contracts for energy and transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or Safe Harbor Tariff accepted by FERC.

**R11.4.** The impact of Firm Point to Point Transmission Service.

**R11.5.** The impact of maintaining roll-over rights for Firm Transmission Service contracts, five years or longer in duration, granting Transmission Customers the right of first refusal to take or continue to take Transmission Service from a Transmission Owner when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**R11.6.** The impact of any Ancillary Services not otherwise included in CBM or TRM.

**R11.7.** Post-backs of redirected or released Firm services.

Re: R11.7 - Being discussed at NAESB - may need to be included. Maybe for temporary "undesignation" of a DNR

**R11.8.** The impact of counter-flows not otherwise accounted for in the ATC calculation.

**R11.9.** The impact of any other services, contracts, or agreements not specified above using transmission that serves Native Load or Firm Network Integration Transmission Service.

**R12.** The Transmission Service Provider shall limit the total impact of all Transmission Service from a specific POR to not exceed sum of the nameplate ratings of all generators at that POR.

**R13.** The Transmission Service Provider shall calculate non-Firm ATC by reducing the TTC by the sum of the firm ETCs, the non-firm ETCs, and the TRM that the Transmission Service Provider has not elected to release allocated to the path.

**R14.** The Transmission Service Provider shall determine the impact of non-firm ETCs based on the following inputs:

**R14.1.** The impact of Non-Firm Network Integration Transmission Service serving Load, to include load forecast error and losses not otherwise included in TRM or CBM.

**R14.2.** The impact of grandfathered non-firm Transmission Service Agreements and bundled contracts for energy and transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or Safe Harbor Tariff accepted by FERC.

**R14.3.** The impact of Non-Firm Point to Point Transmission Service.

**R14.4.** The impact of counterflows not otherwise accounted for in the ATC calculation.

**R14.5.** Capacity utilized for TRM that the Transmission Service Provider has elected to be released as non-firm ATC.

**R14.6.** Post-backs due to the reinstating of Firm from a “Firm-to-Non-Firm” redirect.

**R15.** The Transmission Service Provider shall increase non-firm ATC by the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC, to the extent allowable by the agreement associated with the service, in accordance with established business practices.

**R16.** The Transmission Service Provider shall make publicly available the ATC for each path.

## C. Compliance

To be added with next posting.

## D. Measures

To be added with next posting.

## E. Regional Differences

None.

## F. Associated Documents

### Version History

| Version | Date | Action | Change Tracking |
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Please use this form to submit comments on the 1st draft of standard MOD-028-1 Network Response ATC. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line. If you have questions please contact Andy Rodriquez at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.
The standard drafting team was charged with revising the set of modeling standards.

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The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-028-1 Network Response ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

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   ☐ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area.

   ☐ Yes

   ☐ No

   Comments:

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☐ No

   Comments:

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

   ☐ Yes

   ☐ No

   Comments:

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☐ No

Comments:

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

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Comments:

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| **Individual Commenter Information** | | |
|---|---|---|
| **(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

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   ☐ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The impact of load growth for Network Integration Transmission Service should be included in R11.2.
   The "five years or longer in duration" language should be removed from R11.5. due to the fact that this element of Order 890 is only to be implemented by a Transmission Service Provider (TSP) once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those existing Customers who have not yet been required to commit to five years of service to retain their roll-over rights.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☐ Yes

   ☒ No

   Comments: "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☐ No

   Comments:

**5.** In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: R2. -- For system security reasons, the contingency list details should not be publicly available. Identifying the most critical contingencies publicly could make them a target and thus reduce system reliability. This information should only be shared with those entities demonstrably impacted by such limiting contingencies.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments: The ATC MODs (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide narrative descriptions of these methodologies.

The Applicability section 4.1. through 4.3. and R1., R3., R6. through R10., R13., and R16. should be clarified that ATC need only be calculated and posted for Posted Paths, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.

R11.7. and R14.6. -- Please define the term "Post-back".

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: E. Nick Henery | | |
| Organization: APPA | | |
| Telephone: 202-467-2985 | | |
| E-mail: nhenery@APPAnet.org | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** APPA

**Lead Contact:** **E. Nick Henery**

**Contact Organization:** **APPA**

**Contact Segment:** **Segment 1**

**Contact Telephone:** **202-467-2985**

**Contact E-mail:** **nhenery@APPAnet.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Matt Schull | North Carolina Municipal Power Agency #1 | **SERC** | Segment 5 - Electric Generators |
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   ☐ Yes

   ☒ No

– Comments: The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings.

FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC.

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: This Standard is trying to detail the requirements of ETC and TTC in the same document. A large amount of the sub requirements in R11 and R14 are incorrect and/or being preformed by the wrong Applicable Function. The formula for Non-Firm ATC is incorrect and cannot be complied with by the Applicable Function listed,

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area.

   ☐ Yes

   ☒ No

   Comments: As stated in comment no. 1, TTC is directed to be handled in the FAC series Standards. Therefore the Applicable Functions are incorrect.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

☐ Yes

☒ No

Comments: The requirements in R5 have already been mandated, correctly, in the FAC and other MOD models. To repeat those requirements in this standard will confuse the industry and make it impossible the maintain a workable compliance program for several standards.

**5.** In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☒ No

Comments: The statement as written will impair the operational flexibility of the BES. Any path or network or flowgate that has a rating higher at its POR than the rating of a generator connected at the same POR would limit the transfers at that POR to the generator size. The SDT does not want that. The only time this will be appropriate is when the generator is connected by a radial generator-tie and no other transaction from the system will use this node as the POR.

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: Requirements R1 through R9 should be in the FAC series Standards. The TTC Standards do not address any of the reliability issues that would have been address in FAC-012 and FAC-013, if they had not been written as a fill-in-the-blank standard. The Regional Procedures for determining TTC that are requested in the existing FAC-012 would not have been written as proposed in MOD-028, 029, or 030.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: See comment No. 1

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments: MOD-028 is very confusing and it will be difficult, if not impossible, to integrate into a Compliance program. The Compliance Monitor and the industry will have a very difficult time determining what needs to be accomplished to be compliant.

All of the Documents in this review have been written like a policy and this will not permit a Compliance Monitor to be able to determine if the Registered Applicable Function is conducting themselves in a manner that will meet the objectives of the Standards.

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Greg Rowland | | |
| Organization: Duke Energy | | |
| Telephone: 704-382-5348 | | |
| E-mail: gdrowlan@duke-energy.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☐ Yes

   ☒ No

   Comments: Conditional Firm Service (CFS) and Planning Redispatch Service (PRS) under Order No. 890 create new issues relating to modeling and calculating ATC. Specifically, when PRS is offered to maintain service, modeling for ATC calculations will be impacted during these periods. TTC must be modeled/calculated accounting for the new CFS/PRS requirements.

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: R11.4 should read as follows: The impact of Firm Point to Point Transmission Service adjusted for Post-backs.
   R11.5 should read as follows: The impact of maintaining roll-over rights for Long-Term Firm Transmission Service contracts.
   R11.6 should be deleted or replaced with more specific details of what Ancillary Services impacts are to be considered.
   R11.7 should be deleted, since this is now included in R11.4 above.
   R11.8 should be deleted or replaced with more specific details of how counterflows should be included.
   R11.9 should read as follows: The impact of any other services, contracts, or agreements not specified above using transmission that serves Native Load or Firm Network Integration Transmission Service, adjusted for Post-backs.
   R14.3 should read as follows: The impact of Non-Firm Point to Point Transmission Service, with adjustments for Post-backs.
   R14.4 should be deleted or replaced with more specific details of how counterflows should be included.
   R14.6 should be deleted, since this is now included in R14.3 above.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☒ Yes

   ☐ No

   Comments:

**4.** Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

☐ Yes

☒ No

Comments:

**5.** In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☒ No

Comments: The Transmission Service Provider shall limit the modeling of all Transmission Reservations from a specific generating plant to not exceed the modeled rating of all generators at that plant. Transmission Reservations should be allocated first to DNR's and the remainder allocated proportionately up to the modeled plant rating.

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: R2, R3, R8 and R16 are "communications" in nature and should be removed from NERC requirements and should be put into NAESB business practice standards where the communications requirements can be justified.

Need to re-word the following requirements:
R4. The Planning Coordinator, Reliability Coordinator or Transmission Service Provider shall ensure that the Total Transfer Capability (TTC) for each of its Transmission Service Provider's POR to POD Paths is calculated and up-to-date for use within the Transfer Capability time horizons spedified in MOD-001 R2.
R5. Prior to calculating TTC, the Planning Coordinator, Reliability Coordinator or Transmission Service Provider shall ensure the following components of the base case power flow model used to calculate TTC for the time horizon being studied are updated:
R5.6. Unplanned transmission system Element outages, or unplanned returned to service.
R5.7. Unplanned generation resource outages, or unplanned returned to service.
R5.10. Appropriate Firm Transmission Service Reservations, to eliminate netting of flows to avoid reliability concerns with associated reservations not being scheduled.
R6. The Planning Coordinator, Reliability Coordinator or Transmission Service Provider shall follow these steps in determining the TTC for each path specified:
R7. Each Planning Coordinator and Reliability Coordinator that calculates TTC shall provide its Transmission Service Provider with the TTC for each of the specified paths.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments:

Please use this form to submit comments on the 1st draft of standard MOD-028-1 Network Response ATC. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line. If you have questions please contact Andy Rodriquez at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Narinder K Saini | |
| Organization: | Entergy Services Inc. | |
| Telephone: | 870-543-5420 | |
| E-mail: | nsaini@entergy.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| George Bartlett | Entergy Services Inc. | **SERC** | Transmission Owner |
| Jim Case | Entergy Services Inc. | **SEREC** | Transmission Owner |
| Ed Davis | Entergy Services Inc. | **SERC** | Transmission Owner |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.
The standard drafting team was charged with revising the set of modeling standards.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-028-1 Network Response ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If "No," please identify which directives were 'missed' in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: R 12 is part of ETC for Firm ETC and R15 is adjustment to the Non-Firm ETC which is similar to post back of capacity, therefore, these should be included as sub bullets under R11 and R14 respectively.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☒ Yes

   ☐ No

   Comments: Applicability section correctly includes entities to whom this standard is applicable. However, in requirements the entities are not qualified as "…..that uses the Network Response method….". Appropriate adjustments to the requirements should be made throughout this standard.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☒ No

   Comments: If intent of R5.4 and R5.5 is to update power flow models to include all known outages , R5.6 and R5.7 should be merged with R 5.4 and R5.5 to include planned and unplanned outages.

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☒ No

Comments: The language of R12 does not directly address the intent of Order 890 paragraph 245. It does not provide clear instructions for treatment of multiple reservation from a POR (generator) other than limiting the impact to name plate rating. We suggest that a uniform method, or alternate methods be included for treating these reservations to address Order 890 paragraph 245.

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: From R5.11, language "with which coordination agreements have been executed" should be struck. In R6.3, "interfaces" should be changed to ties/interconnections. In R7, "each of the specified' should be struck and "idenfied in R3" should be added after paths. From R11.5, the language "five years or longer in duration…..renewal" should be struck and "as applicable" be added after contracts.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments:

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| Name: Steve Myers | | |
| Organization: ERCOT | | |
| Telephone: 512-248-3077 | | |
| E-mail: smyers@ercot.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☒ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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The standard drafting team was charged with revising the set of modeling standards.

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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If "No," please identify which directives were 'missed' in the comments area.

   ☒ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☒ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

   ☒ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☐ No

Comments: See IRC comments submitted by Charles Yeung.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments: ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area and there has been no reservation of transmission capacity in ERCOT.

Available Transfer Capability is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. The ERCOT Interconnection has already moved "beyond" ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therfore both ERCOT and SPP are notified when the DC Tie capability is reduced.

Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.

In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.

In the current and future ERCOT market design the method of calculating ATC, TTC and the use of CBM and TRM are not applicable to the ERCOT Region. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance.

Please use this form to submit comments on the 1st draft of standard MOD-028-1 Network Response ATC. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line. If you have questions please contact Andy Rodriquez at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Dave Folk | |
| Organization: | FirstEnergy Corp. | |
| Telephone: | 330-384-4668 | |
| E-mail: | folkd@firstenergycorp.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Richard Kovacs | FirstEnergy Corp. EDPP | | |
| Phil Bowers | FirstEnergy Corp. EDPP | | |
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   ☒ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: However, the term "Post-backs" is industry jargon and should be replaced with the term "reinstatement" to add clarity.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☒ Yes

   ☐ No

   Comments: MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once, eliminate duplication, and simplify the applicability sections of MOD-028, 029, and 030.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☒ No

   Comments: R 5.11 requires inclusion of the data provided by adjacent Transmission Service Providers and any other TSP with which coordination agreements have been executed; however, this standard does not include a requirement for adjacent TSPs to provide this data nor for executing coordination agreements with other TSPs.

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☒ Yes

☐ No

Comments: However, the phrase "not exceed" can be replaced with the word "the" since the term "limiting the total impact" is synononomous.

6. Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☒ Yes

☐ No

Comments:

7. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

8. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments: The standard should include specifics of methods for complying with the term "publicly available" such as posting on OASIS, a corporate web page, etc. (This concept is mentioned in all MOD-028, MOD-029, and MOD-030.)

R5.10 needs more clarity. While it provides leeway with respect to recognizing Firm Reservations, the term appropriate is subjective in nature and requires quidance on determing what is appropriate and what is not.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Roger Champagne | |
| Organization: | Hydro-Québec TransÉnergie | |
| Telephone: | 514 289-2211, X 2766 | |
| E-mail: | champagne.roger.2@hydro.qc.ca | |

| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Danielle Beaulieu | Hydro-Québec TransÉnergie | **NPCC** | 1 |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission’s (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC’s directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If “No,” please identify which directives were ‘missed’ in the comments area.

   ☒ Yes

   ☒ No

   Comments: We believe the fundemental concerns of the FERC Orders 890 and 693 are identified in the standard. However, there are many detailed requirements in Orders 890 and 693 such that there has not been adequate time to do a thorough comparison. It is expected that the supplemental SAR would be addressing the issues that remain outstanding from those Orders.

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If “No,” please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☒ Yes

   ☒ No

   Comments: We agree with the entities listed. However, the description of the applicability for the PC and RC are not valid. The PC and RC provide input to ATC calculations, but they do not calculate ATCs. Suggest replacing 'ATCs' with 'TTCs' in the description of Requirement 4.1 and 4.2. Also, the language in these Applicability descriptions should be the consistent between MOD-028 and MOD-029.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If “Yes,” please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☒ No

   Comments:

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If “No,” please

suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: R1: MOD-028 requires 'a list', MOD-029 requires 'a description'. The language for this requirement between these two MODs should be consistent.
R2: This list of contingencies could contain critical infrastructure information. The phrase "consistent with CEII policies" should be added to the end of this requirement.
R6.1: The intent of the text of Requirement 6.1 in MOD-028 and MOD-029 seems to be the same. If the intent is the same, the language should be the same.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets.

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments:

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Ron Falsetti | | |
| Organization: IESO | | |
| Telephone: 905-855-6187 | | |
| E-mail: ron.falsetti@ieso.ca | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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   ☒ Yes

   ☒ No

   Comments: We agree that the drafting team appears to have addressed all the FERC directives. However, we feel that this and the other MOD standards need revisions to properly align responsibilities and eliminate duplications (also see our comments on the other MOD standards).

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: We feel that R11.1, R11.2, R11.6 and R14.1 leave room for double counting of components that shold have been taken care of by TRM and CBM. Further, we do not understand why the CBM component is excluded from R13. If the omission is based on the rationale that CBM could be offered as non-firm ATC, then wouldn't TRM be treated in the same manner?

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☐ Yes

   ☒ No

   Comments: The Planning Coordinator and Reliability Coordinator do not calculate ATCs. We suspect the reason that they are included in the applicability section is for their role in determining TTC. However, their roles are incorrectly stated in the applicability description.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☒ Yes

   ☒ No

   Comments: While the component list appears to be complete, we find it difficult to keep track of or understand the rationale behind putting this requirement in this standard, while being uncertain of what changes are to be made to FAC-012 and -013. If those parts of FAC-012 and -013 that relate to TTC calculation are to be absorbed in this standard, then we'd think that having R5 (and R6) alone may not be sufficient. On the other hand, if FAC-012 and -013 are to remain as is or be moved to other standards, then we do not see the need to replicate partical requirements in MOD-028.

Note that the supplementarty SAR indicates that: "Specifically, the following Standards may be modified, transferred to NAESB or retired:

FAC-012 Transfer Capability Methodology
FAC-013 Establish and Communicate Transfer Capabilities

The SDT needs to be more specific and certain of its direction on these two standards to help the industry better understand and track changes.

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☐ Yes

☐ No

Comments:

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☐ Yes

☒ No

Comments: We have a question on R13 with respect to the omision of CBM (see our comments under Q2). Further, in R15, we do not understand what would be the items that are "by the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC" when increasing non-firm ATC.

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☐ Yes

☒ No

Comments: However, please note that some markets do not offer physical transmission services and hence some of the requirements in this standard do not apply to these entities.

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Comments: Please see our comments on the Supplementary SAR. Also, as indicated under Q4, we are concerned with the lack of details and specific direction on treatment of FAC-012 and -013, and how changes to these two standards will be coordinated with the requirements in this standard (and MOD-029 and MOD-030).

Please use this form to submit comments on the 1st draft of standard MOD-028-1 Network Response ATC. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line. If you have questions please contact Andy Rodriquez at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

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|---|---|
| Group Comments (Complete this page if comments are from a group.) | |
| **Group Name:** | IRC Standards Review Committee |
| **Lead Contact:** | **Charles Yeung** |
| **Contact Organization:** | **SPP** |
| **Contact Segment:** | **2** |
| **Contact Telephone:** | **823-724-6142** |
| **Contact E-mail:** | **cyeung@spp.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Jim Castle | NYISO | **NPCC** | 2 |
| Alicia Daugherty | PJM | **RFC** | 2 |
| Ron Falsetti | IESO | **NPCC** | 2 |
| Matt Goldberg | ISO-NE | **NPCC** | 2 |
| Brent Kingsford | CAISO | **WECC** | 2 |
| Steve Myers | EROCT | **ERCOT** | 2 |
| Anita Lee | AESO | **WECC** | 2 |
| Bill Phillips | MISO | **RFC+** | 2 |
| | | **MRO+** | |
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☐ No

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Matthew F. Goldberg | |
| Organization: | ISO New England | |
| Telephone: | 413 535 4029 | |
| E-mail: | mgoldberg@iso-ne.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-028-1 Network Response ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission’s (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC’s directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If “No,” please identify which directives were ‘missed’ in the comments area.

   ☒ Yes

   ☒ No

   Comments: We believe the fundemental concerns of the FERC Orders 890 and 693 are identified in the standard. However, there are many detailed requirements in Orders 890 and 693 such that there has not been adequate time to do a thorough comparison.

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If “No,” please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: We suggest rephrasing R11 and R14 so that it also states that: "The TSP shall determine the impact of firm ETCs based on the inputs listed below. If any of the inputs listed below refer to a product or service that is not contained in the TSP's FERC-approved Tariff, the TSP shall document this fact in their ATCID and the value of such input(s) in the ETC calculation shall be considered to be zero MW."

   The wording of 11.8 and 14.4 imply that the TSP MUST include the impact of counterflow. We do not agree that the impact of counterflow MUST be considered. It should up to the TSP as to if, when and how counter flow is considered. The requirement should be worded to allow for that flexibility and require that the TSP document how it is considered.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☒ Yes

   ☒ No

   Comments: We agree with the entities listed. However, the description of the applicability for the PC and RC are not valid. The PC and RC provide input to ATC calculations, but they do not calculate ATCs. Suggest replacing 'ATCs' with 'TTCs' in the description.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If “Yes,” please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☒ No

Comments:

**5.** In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: R1. MOD-028 requires 'a list', MOD-029 requires 'a description'. The language for this requirement between these two MODs should be consistent.
R2. This list of contingencies could contain critical infrastructure information. The phrase "consistent with CEII policies" should be added to the end of this requirement.
R6.1 The intent of the text of Requirement 6.1 in MOD-028 and MOD-029 seems to be the same. If the intent is the same, the language should be the same.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the services (e.g., the offering of firm point to point service, see R.11.4) to which these requirements apply are not offered by Transmission Service Providers that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero in the markets administered by these TSPs. For example, over the Pool Transmission Facilities in New England, all capability is considered available to the market (i.e., the Total Transfer Capability) until real-time scheduling occurs. With the current arrangement of these proposed standards, the ATC Implementation Document would clearly document how the TSP complies with these standards, based on what services are offered through the Commission-approved tariff and/or market rules .

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments:

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Tom Mielnik | |
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| E-mail: | tcmielnik@midamerican.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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The standard drafting team was charged with revising the set of modeling standards.

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1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If "No," please identify which directives were 'missed' in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: 1. R11 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm existing transmission committements based on an appropriate level of the following inputs." 2. Existing transmission commitments should not be listed in capatalized letters unless a definition is going to be developed for the NERC Glossary.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☐ Yes

   ☒ No

   Comments: The Functional Entity as provided in A.4. should not be qualified, for example, A.4. should just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☒ No

   Comments:

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

   ☒ Yes

   ☒ No

Comments: The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests and show how the Transmission Service Provider than reviews the impacts to meet the requirement.

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: 1. For R1, R2, R4, R5, R6, and R7, the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. 2. R6.2 and R6.3 use "first contingency" which implies that the only planning criteria to be used is first contingency outages. The TTC must be based upon the appropriate planning criteria whatever that is. The references to first contingency should be made more generic. 3. R3, R8 and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration. 4. R11 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropraite level of " the following inputs. 5. R14 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the area to maximize the non-firm offerings in the operating horizon. I suggest wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC."

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments: The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The purpose in MOD-028-1 be revised to replace "uniform" with "transparent".

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Dennis Kimm | |
| Organization: | MidAmerican Energy Generation/Trading | |
| Telephone: | 515 252 6737 | |
| E-mail: | ddkimm@midamerican.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If "No," please identify which directives were 'missed' in the comments area.

   ☐ Yes

   ☒ No

   Comments: The entire point of 890 and 693 appeared to be not only for transparency, but consistency.

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☐ Yes

   ☐ No

   Comments: This is very difficult because the functional model seems to be very specific, but roles within a utility are not so clearly defined.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☒ Yes

   ☐ No

   Comments: A consistent way of modeling all of the things listed in R5 should be clearly identified within the standard (partial path reservations, conditional firm service, outages that last 1 day for a monthly model, etc.)

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

   ☒ Yes

   ☐ No

Comments: The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. This appears to make unit specific service of less value then service that lists a control area for redirecting that service.

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: This is a fill-in-the-blank standard.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: No requirement for consistency

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments: This standard should be combined with MOD-30 and the requirements should be written to require consistency.

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|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** Midwest Reliability Organization (MRO)

**Lead Contact:** **Tom Mielnik**

**Contact Organization:** **MRO for Group (MEC for lead contact)**

**Contact Segment:** **10**

**Contact Telephone:** **563-333-8129**

**Contact E-mail:** **tcmielnik@midamerican.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Neal Balu | WIPS | **MRO** | 10 |
| Terry Bilke | MISO | **MRO** | 10 |
| Robert Coish, Chair | MHEB | **MRO** | 10 |
| Carol Gerou | MP | **MRO** | 10 |
| Ken Goldsmith | ALT | **MRO** | 10 |
| Jim Haigh | WAPA | **MRO** | 10 |
| Joe Knight | GRE | **MRO** | 10 |
| Pam Oreschnick | XEL | **MRO** | 10 |
| Dave Rudolph | BEPC | **MRO** | 10 |
| Eric Ruskamp | LES | **MRO** | 10 |
| Mike Brytowski, Secretary | MRO | **MRO** | 10 |
| 28 Additional MRO Members | Not Named Above | **MRO** | 10 |
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   ☒ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: 1. R11 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm existing transmission committements based on an appropriate level of the following inputs." 2. Existing transmission commitments should not be listed in capatalized letters unless a definition is going to be developed for the NERC Glossary.

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   ☐ Yes

   ☒ No

   Comments: The MRO believes that the Functional Entity as provided in A.4. should not be qualified, for example, the MRO recommends that A.4. just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☒ No

   Comments:

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

   ☒ Yes

☒ No

Comments: The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests and show how the Transmission Service Provider than reviews the impacts to meet the requirement.

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: 1. The MRO believes that for R1, R2, R4, R5, R6, and R7, the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. 2. R6.2 and R6.3 use "first contingency" which implies that the only planning criteria to be used is first contingency outages. The TTC must be based upon the appropriate planning criteria whatever that is. The references to first contingency should be made more generic. 3. R3, R8 and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration. 4. R11 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropraite level of " the following inputs. 5. R14 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the MRO to maximize the non-firm offerings in the operating horizon. The MRO suggests wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC."

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments: The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The MRO recommends that the purpose in MOD-028-1 be revised to replace "uniform" with "transparent".

Please use this form to submit comments on the 1st draft of standard MOD-028-1 Network Response ATC. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line. If you have questions please contact Andy Rodriquez at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
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| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| | ☒ | 10 — Regional Reliability Organizations and Regional Entities |

| Group Comments (Complete this page if comments are from a group.) | |
|---|---|
| **Group Name:** | NPCC CP9 Working Group |
| **Lead Contact:** | **Guy V. Zito** |
| **Contact Organization:** | **Northeast Power Coordinating Council** |
| **Contact Segment:** | **10** |
| **Contact Telephone:** | **212-840-1070** |
| **Contact E-mail:** | **gzito@npcc.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Kathleen Goodman | ISO-New England | **NPCC** | 2 |
| Roger Champagne | HydroQuebec TransEnergieq | **NPCC** | 1 |
| Ralph Rufrano | New York Power Authority | **NPCC** | 1 |
| Al Adamson | New York State Reliability Council | **NPCC** | 10 |
| Guy ZIto | NPCC | **NPCC** | 10 |
| Greg Campoli | New York ISO | **NPCC** | 2 |
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## Background Information

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.
The standard drafting team was charged with revising the set of modeling standards.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-028-1 Network Response ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission’s (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC’s directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If “No,” please identify which directives were ‘missed’ in the comments area.

   ☒ Yes

   ☒ No

   Comments: We believe the fundemental concerns of the FERC Orders 890 and 693 are identified in the standard. However, there are many detailed requirements in Orders 890 and 693 such that there has not been adequate time to do a thorough comparison. It is expected that the supplemental SAR would be addressing the issues that remain outstanding from those Orders.

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If “No,” please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☒ Yes

   ☒ No

   Comments: We agree with the entities listed. However, the description of the applicability for the PC and RC are not valid. The PC and RC provide input to ATC calculations, but they do not calculate ATCs. Suggest replacing 'ATCs' with 'TTCs' in the description of Requirement 4.1 and 4.2. Also, the language in these Applicability descriptions should be the consistent between MOD-028 and MOD-029.

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If “Yes,” please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☒ No

   Comments:

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If “No,” please

suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: R1: MOD-028 requires 'a list', MOD-029 requires 'a description'. The language for this requirement between these two MODs should be consistent.
R2: This list of contingencies could contain critical infrastructure information. The phrase "consistent with CEII policies" should be added to the end of this requirement.
R6.1: The intent of the text of Requirement 6.1 in MOD-028 and MOD-029 seems to be the same. If the intent is the same, the language should be the same.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets.

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments:

Please use this form to submit comments on the 1st draft of standard MOD-028-1 Network Response ATC. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line. If you have questions please contact Andy Rodriquez at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

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|---|---|
| Group Comments (Complete this page if comments are from a group.) | |
| **Group Name:** | Public Service Commission of South Carolina |
| **Lead Contact:** | **Phil Riley** |
| **Contact Organization:** | **Public Service Commission of South Carolina** |
| **Contact Segment:** | **9** |
| **Contact Telephone:** | **803-896-5154** |
| **Contact E-mail:** | **philip.riley@psc.sc.gov** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mignon L. Clyburn | PSCSC | **SERC** | 9 |
| G. O'Neal Hamilton | PSCSC | **SERC** | 9 |
| John E. "Butch" Howard | PSCSC | **SERC** | 9 |
| Randy Mitchell | PSCSC | **SERC** | 9 |
| C. Robert "Bob" Moseley | PSCSC | **SERC** | 9 |
| David A. Wright | PSCSC | **SERC** | 9 |
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1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If "No," please identify which directives were 'missed' in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☒ Yes

   ☐ No

   Comments:

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☒ No

   Comments:

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

   ☒ Yes

   ☐ No

   Comments:

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☒ Yes

☐ No

Comments:

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

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<tr><td rowspan="10">☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☐ NPCC<br>☐ RFC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
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<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | SERC Available Transfer Capability Working Group (ATCWG) |
| **Lead Contact:** | **John Troha** |
| **Contact Organization:** | **SERC Reliability Corporation** |
| **Contact Segment:** | **10 - RRO** |
| **Contact Telephone:** | **704-948-0761** |
| **Contact E-mail:** | **jtroha@serc1.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Darrell Pace | Alabama Electric Cooperative, Inc | **SERC** | 10 |
| Helen Stines | Alcoa Power Generating, Inc. | | |
| Eugene Warnecke | Ameren | | |
| Don Reichenbach | Duke | | |
| Joachim Francois | Entergy | | |
| Ross Kovacs | Georgia Transmission Corporation | | |
| Larry Middleton | Midwest ISO | | |
| Jerry Tang | Municipal Electric Authority of Georgia | | |
| John Troha | SERC Reliability Corporation | | |
| Al McMeekin | South Carolina Electric and Gas Company | | |
| Stan Shealy | South Carolina Electrica nd Gas Company | | |
| Carter Edge | SERC Reliability Corporation | | |
| DuShaune Carter | Southern Company Services, Inc. -Trans | | |
| Bryan Hill | Southern Company Services, Inc. -Trans | | |
| Doug Bailey | Tennessee Valley Authority | | |
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   ☐ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☐ Yes

   ☒ No

   Comments: The applicability section needs clarification. Referencing R4 and R5, they should apply only to those entities performing the function. The standard should not require the calculations be made by the PC and RC, but should be applicable to the designated entitiy performing these calculations . The designated entity must be specified as a requirement in this standard. For example: The TSP, PC and RC must specify and agree to the entity that performs this function in the TSP's ATCID as required in MOD 1. The current revision of MOD-001 states the following requirement as R1: "Each Transmission Service Provider, and its associated Planning Coordinators and Reliability Coordinators, shall agree upon and implement one or more of the ATC methodologies specified in Reliability Standard MOD-028, MOD-029, and MOD-030 for use in determining Transfer Capabilities of those Facilities under the tariff administration of that Transmission Service Provider." The requirements of MOD-0028 should refer to the Designated Entity specified through this requirement. The following are examples of how this would be implemented in the standard:

   B. Requirements
   R4. Each Designated Entity shall ensure that the Total Transfer Capability (TTC) for each of its Transmission Service Provider's POR to POD Paths is calculated and up-to-date for use within the Transfer Capability time horizons specified in MOD-001 R2.
   R5. Prior to calculating TTC, each Designated Entity shall update the following components of the base case power flow model it uses to calculate TTC for the time horizon being studied:

**4.** Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

☐ Yes

☒ No

Comments:

**5.** In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

☐ Yes

☐ No

Comments:

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: See comments in Question 3.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments: Standard is not clear as to what applies to long-term timeframe and short-term timeframe.

Reference in R12 to generator nameplate should be changed to maximum capability since in some conditions the generator can exceed nameplate rating.

Please use this form to submit comments on the 1st draft of standard MOD-028-1 Network Response ATC. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line. If you have questions please contact Andy Rodriquez at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** Southern Company

**Lead Contact:** **DuShaune Carter**

**Contact Organization:** **Southern Company Services**

**Contact Segment:**

**Contact Telephone:** **205-257-5775**

**Contact E-mail:** **ddcarter@southernco.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| JT Wood | Southern Company Services | **SERC** | 1 |
| Roman Carter | Southern Company Services | **SERC** | 1 |
| Gary Gorham | Southern Company Services | **SERC** | 1 |
| Marc Butts | Southern Company Services | **SERC** | 1 |
| Bill Botters | Southern Company Services | **SERC** | 1 |
| Ron Carlsen | Southern Company Services | **SERC** | 1 |
| Jim Howell | Southern Company Services | **SERC** | 1 |
| Jeremy Bennett | Southern Company Services | **SERC** | 1 |
| Jim Viikinsalo | Southern Company Services | **SERC** | 1 |
| Reed Edwards | Southern Company Services | **SERC** | 5 |
| Dean Ulch | Southern Company Services | **SERC** | 1 |
| Garey Rozier | Southern Company Services | **SERC** | 5 |
| Karl Moor | Southern Company Services | **SERC** | 1 |
| Chuck Chakravarthi | Southern Company Services | **SERC** | 1 |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.
The standard drafting team was charged with revising the set of modeling standards.

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-028-1 Network Response ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "NR ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If "No," please identify which directives were 'missed' in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area**.**

   ☒ Yes

   ☐ No

   Comments:

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

   ☐ Yes

   ☒ No

   Comments:

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

   ☐ Yes

   ☒ No

   Comments: We interpret the intent of paragraph 245 to imply that a generator should not be modeled at a level exceeding its maximum capability. With this interpretation, service could be granted up to the capability of the generator for each different POD. This is not allowed as R12 is currently drafted.

**6.** Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

☐ Yes

☒ No

Comments: R5.11 Comments. It may not be feasible to include all data from neighboring systems (e.g. PC or RC may not be able to incorporate all Special Protection schemes in a base case for TTC calculation). Also, the timeframes for which the values are being calculated may not allow for the incorporation of this data.

**7.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: R12 requires the TSP to limit the total impact of all Transmission Service from a "POR" (multiple generators) not a specific "generator" as written in Order 890.

**8.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

Comments:

1. As drafted, it is not completely clear as to which of the requirements would apply to long-term planning and which requirements would not apply.

2. The group should consider how conditional firm will be treated with respect to ETC and the TTC calculation.

3. The reference in R12 to "nameplate" should be change to "maximum capability." Under certain conditions, the output of a generator can exceed the value of its nameplate.

**Consideration of Comments — 2nd Draft of Standard MOD-028-1 — Network Response ATC (Project 2006-07)**

The ATC Standard Drafting Team requesters thank all commenters who submitted comments on the first draft of standard MOD-028-1, Network Response (Project 2006-07). This standard was posted for a 30-day public comment period from May 25 through June 24, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 17 sets of comments, including comments from 76 different people from more than 40 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team has significantly redrafted the standard. The drafting team has addressed a significant number of the concerns expressed, but the changes have been so extensive that the revised standard bears very little resemblance to the last posted draft. Major changes include:

- A new term was defined to support a change in the name of the methodology described in the standard – Area Interchange Methodology
- The title was changed from, 'Network Response ATC' to 'Area Interchange Methodology' to have a title that is more self-descriptive.
- The Purpose statement was enhanced to clarify that the standard's purpose is to 'increase consistency and transparency in the development of transfer capability calculations' rather than to 'increase consistency and transparency in the development and documentation of ATC.'
- The Applicability was modified to eliminate the Planning Coordinator and Reliability Coordinator and to add the Transmission Operator. R1, which required the Planning Coordinator and Reliability Coordinator to provide specific information about contingencies and assumptions used to determine Transfer Capabilities to the Transmission Service Provider was eliminated. The intent of the requirement was to ensure that these contingencies and assumptions were respected by the Transmission Service Provider in the determination of TTC – and in the revised standard's R1, the Transmission Service Provider must document these contingencies, and other information used in the calculation of TTC in the Transmission Service Provider's Available Transfer Capability Implementation Document.
- R2, R3, R8 and R16 all required the Transmission Service Provider to make information publicly available, and all four of these requirements have been deleted from the revised standard. NAESB's business practices will address all ATC-related posting requirements.
- R4 which required the Planning Coordinator and Reliability Coordinator to ensure that TTC for each of the Transmission Service Provider's paths was calculated according to a schedule has been deleted. All requirements for the Planning Coordinator and Reliability Coordinator to calculate TTC have been removed from the standard and have been replaced with more detailed requirements for the Transmission Service Provider and/or the Transmission Operator to calculate TTC.
- R5 which required the Planning Coordinator and Transmission Operator to update the models used to calculate TTC has been revised so that the requirement is applied to the

Transmission Operator. The various components of the model that must be updated have been modified to provide more specificity to the elements of the model that must be used in calculating TTC.

- R6 outlined a process for the Planning Coordinator and Reliability Coordinator to follow in determining TTC for a path – and this requirement has been modified so that it applies to the Transmission Operator. The steps in the process have been modified to improve the clarity of the steps in the process.
- R7 required the Planning Coordinator and Reliability Coordinator to provide the Transmission Service Provider with the TTCs they had calculated – and this requirement has been revised so that it applies to the Transmission Operator. In the revised requirement, the Transmission Operator must make the TTCs it has calculated available to the Transmission Service Provider within five days of the determination of those TTCs.
- R9, R10 and R13 required the Transmission Service Provider to calculate ATC in accordance with very high-level formulas and requirements in MOD-001. In the revised standard there is a very detailed formula for calculating Firm ATC (R10) and a very detailed formula for calculating Non-Firm ATC (R11).
- R11 required the determination of Firm ETC in accordance with a set of 'inputs'. This requirement has been modified so that it includes a very detailed formula for calculating Firm ETC (R8).
- R12 required the Transmission Service Provider to limit the total impact of all transmission service from a specific POR to not exceed the sum of the nameplate ratings of all generators at that POR. The drafting team could not find a reliable approach to specifying how this could be implemented and the requirement was deleted.
- R13 and R15 were 'rules' relative to the calculation of ATC and have been deleted as separate requirements – they are now addressed in the algorithm for calculating non-firm ATC in the revised standard (R12).
- R14 required the determination of Non-Firm ETC in accordance with a high level formula. This requirement has been modified so that it includes a very detailed algorithm for calculating Non-Firm ETC (R9).
- Added measures and compliance information.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Anita Lee (G2) | AESO | | ✓ | | | | | | | | |
| 2. | Darrell Pace (G7) | Alabama Electric Coop. | | | | ✓ | ✓ | ✓ | | | | |
| 3. | Helen Stines (G7) | Alcoa Power Generating, Inc. | | | | | | ✓ | ✓ | ✓ | | |
| 4. | Ken Goldsmith | ALT | ✓ | | | | ✓ | | | | | |
| 5. | Eugene Warnecke (G7) | Ameren | | | ✓ | | | ✓ | | | | |
| 6. | E. Nick Henery | APPA | ✓ | | ✓ | ✓ | | | | | | |
| 7. | Dave Rudolph | BEPC | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 8. | Abbey Nulph | Bonneville Power Administration (BPA) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 9. | Brent Kingsford (G2) | CAISO | | ✓ | | | | | | | | |
| 10. | Don Reichenbach (G7) | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 11. | Greg Rowland | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 12. | Joachim Francois (G7) | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 13. | Ed Davis | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 14. | George Bartlett | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 15. | Jim Case | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 16. | Narinder K Saini | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 17. | Steve Myers (I) (G2) | ERCOT | | ✓ | | | | | | | | ✓ |
| 18. | Dave Folk | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 19. | Phil Bowers | FirstEnergy Corp. EDPP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 20. | Richard Kovacs | FirstEnergy Corp. EDPP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 21. | Ross Kovacs (G7) | Georgia Transmission Corporation | ✓ | | ✓ | | | | | | | |
| 22. | Joe Knight | Great River Eenergy | ✓ | | ✓ | | ✓ | | | | | |
| 23. | Danielle Beaulieu | Hydro-Québec TransÉnergie | ✓ | | | | | | | | | |
| 24. | Roger Champagne (G4) | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 25. | Ron Falsetti (I) (G2) | IESO | | ✓ | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 26. | Charles Yeung (G2) | IRC Standards Review Committee | | ✓ | | | | | | | | |
| 27. | Matt Goldberg (I)(G2) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 28. | Kathleen Goodman (G4) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 29. | Eric Ruskamp | LES | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 30. | Robert Coish (G3) | Manitoba Hyrdo EB | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 31. | Jerry Tang (G7) | MEAG | ✓ | | ✓ | | ✓ | | | | | |
| 32. | Tom Mielnik (I) (G3) | MidAmerican Energy Company (MEC) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 33. | Dennis Kimm (G3) | MidAmerican Energy Generation/Trading (MEC Trading) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 34. | Larry Middleton (G7) | Midwest ISO | | ✓ | | | | | | | | |
| 35. | Carol Gerou | Minnesota Power (MP) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 36. | Bill Phillips (G2) | MISO | | ✓ | | | | | | | | |
| 37. | Terry Bilke (G3) | MISO | | ✓ | | | | | | | | |
| 38. | Mike Brytowski | MRO | | | | | | | | | | |
| 39. | Greg Campoli (G4) | New York ISO (NYISO) | | ✓ | | | | | | | | |
| 40. | Jim Castle (G2) | New York ISO | | ✓ | | | | | | | | |
| 41. | Ralph Rufrano (G4) | New York Power Authority (NYPA) | ✓ | | ✓ | | | | | | | |
| 42. | Al Adamson (G4) | New York State Reliability Council | | | | | | | | | | ✓ |
| 43. | Matt Schull (G1) | North Carolina MPA #1 | | | ✓ | ✓ | ✓ | ✓ | | | | |
| 44. | Guy V. Zito | NPCC WG | | | | | | | | | | |
| 45. | Alicia Daugherty (G2) | PJM | | ✓ | | | | | | | | |
| 46. | C. Robert Moseley (G5) | PSC of South Carolina (PSC SC) | | | | | | | | | ✓ | |
| 47. | David A. Wright (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 48. | G. O'Neal Hamilton (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 49. | John E. Howard (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 50. | Mignon L. Clyburn (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 51. | Phil Riley (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 52. | Randy Mitchell (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 53. | John Troha (G7) | SERC ATCWG | | | | | | | | | | ✓ |
| 54. | Carter Edge (G7) | SERC RC | | | | | | | | | | ✓ |
| 55. | Al McMeekin (G7) | South Carolina Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |
| 56. | Stan Shealy (G7) | South Carolina Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |
| 57. | Bryan Hill (G7) | South Carolina Services | ✓ | | | | ✓ | | | | | |
| 58. | Bill Botters (G6) | Southern Company Services (SCS) | ✓ | | | | ✓ | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 59. | Chuck Chakravarthi (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 60. | Dean Ulch (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 61. | DuShaune Carter (G6) (G7) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 62. | Garey Rozier (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 63. | Gary Gorham (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 64. | Jeremy Bennett (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 65. | Jim Howell (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 66. | Jim Viikinsalo (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 67. | JT Wood (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 68. | Karl Moor (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 69. | Marc Butts (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 70. | Reed Edwards (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 71. | Roman Carter (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 72. | Ron Carlsen (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 73. | Doug Bailey (G7) | TVA | ✓ | | ✓ | | ✓ | | | | | |
| 74. | Jim Haigh | WAPA | ✓ | | | | | ✓ | | | | |
| 75. | Neal Balu (G3) | WIPS | | | | | | | | | | |
| 76. | Pam Oreschnick | XEL | ✓ | | ✓ | | ✓ | ✓ | | | | |

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – APPA
G2 – IRC Standards Review Committee
G3 – MRO Group Members
G4 – NPCC CP9 Working Group
G5 – PSC of South Carolina
G6 – Southern Company Servies
G7 – SERC Available Transfer Capability Working Group (ATCWG)

## Index to Questions, Comments, and Responses

1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If "No," please identify which directives were 'missed' in the comments area.

**Summary Consideration:** None of the stakeholders who responded to this question provided a specific directive from either of the FERC Orders relative to MOD-028 that was missing in the proposed MOD-028. Several stakeholders expressed concerns that insufficient time had been allocated to fully review the Orders against the proposed standard. The Drafting Team met with members of FERC staff to gain more insight into the directives in the two Orders and determined that some directives needed additional attention – and the drafting team remedied this in draft 2 of the proposed standard. The drafting team will post a matrix that shows each of the directives and identifies the standard and requirement where the directive has been addressed.

| **Question #1** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings.<br><br>FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC. |
| **Response:** FERC has provided the Drafting Team additional guidance regarding this area. The TTC Standard will be moved from the FAC standards to the MOD standards. | | | |
| Duke Energy | | ☑ | Conditional Firm Service (CFS) and Planning Redispatch Service (PRS) under Order No. 890 create new issues relating to modeling and calculating ATC. Specifically, when PRS is offered to maintain service, modeling for ATC calculations will be impacted during these periods. TTC must be modeled/calculated accounting for the new CFS/PRS requirements. |
| **Response:** It is important to note that Planning Redispatch and CFS are only offered to long-term (one year or longer) service requests and that these two service types are considered firm when ATC is available in the short-term horizons. We believe this will be handled as a part of the NAESB work. | | | |
| MEC Trading | | ☑ | The entire point of 890 and 693 appeared to be not only for transparency, but consistency. |
| **Response:** Agree. The SDT thanks you for your comments. | | | |
| NPCC WG | ☑ | ☑ | We believe the fundamental concerns of the FERC Orders 890 and 693 are identified in the standard. |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| HQT | | | However, there are many detailed requirements in Orders 890 and 693 such that there has not been adequate time to do a thorough comparison. It is expected that the supplemental SAR would be addressing the issues that remain outstanding from those Orders. |
| **Response:** The SDT thanks you for your comments. The drafting team will post a matrix that shows each of the directives and identifies the standard and requirement where the directive has been addressed. | | | |
| ISO NE | ☑ | ☑ | We believe the fundamental concerns of the FERC Orders 890 and 693 are identified in the standard. However, there are many detailed requirements in Orders 890 and 693 such that there has not been adequate time to do a thorough comparison. |
| **Response:** The SDT thanks you for your comments. The drafting team will post a matrix that shows each of the directives and identifies the standard and requirement where the directive has been addressed. | | | |
| IESO | ☑ | ☑ | We agree that the drafting team appears to have addressed all the FERC directives. However, we feel that this and the other MOD standards need revisions to properly align responsibilities and eliminate duplications (also see our comments on the other MOD standards). |
| **Response:** The drafting team looked for these examples and considered this when modifying the standards. The drafting team did modify the applicability of this and other standards in support of the stakeholder comments indicating that some of the requirements had been in appropriately applied to the Planning Coordinator and Reliability Coordinator. | | | |
| IRC | ☑ | ☑ | We agree that the drafting team appears to have addressed all the FERC directives. However, we feel that this and the other MOD standards need revisions to properly align responsibilities and eliminate duplcations (also see our comments on the other MOD standards). We should resist this question again when updated standard versions are posted. |
| **Response:** The drafting team looked for these examples and considered this when modifying the standards. The drafting team did modify the applicability of this and other standards in support of the stakeholder comments indicating that some of the requirements had been in appropriately applied to the Planning Coordinator and Reliability Coordinator. | | | |
| ERCOT | ☑ | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See the response to IRC's comments. | | | |
| Entergy | ☑ | | |
| FirstEnergy | ☑ | | |
| MEC | ☑ | | |
| MRO | ☑ | | |
| PSC SC | ☑ | | |
| SCS | ☑ | | |
| SERC ATCWG | ☑ | | |

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

**Summary Consideration:** The SDT made several changes to the standard to address the comments received, including the following:
Modified R8 (now

Modified R11 (now R8) so that instead of requiring the Transmission Service Provider to 'determine the impact' of firm ETCs based on a set of inputs, the Transmission Service Provider must use the following algorithm to 'calculate' Firm ETC:

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Modified R14 (now R11) so that instead of requiring the Transmission Service Provider to 'determine the impact' of Non-firm ETCs based on a set of inputs, the Transmission Service Provider must use the following algorithm to 'calculate' Non-Firm ETC:

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflows_{NF}$$

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | This Standard is trying to detail the requirements of ETC and TTC in the same document. A large amount of the sub requirements in R11 and R14 are incorrect and/or being preformed by the wrong Applicable Function. The formula for Non-Firm ATC is incorrect and cannot be complied with by the Applicable Function listed. |
| **Response:** The drafting team considered this when modifying the standards, and redrafted the standard in hopes of addressing your concerns.<br>R11 and R14 required the TSP to determine the impact of firm and non-firm ETC – and the TSP is the functional entity that should perform these calculations, so the applicability was not changed.<br>The drafting team did revisit the sub-requirements for determining ETCs and converted the 'inputs' into elements in algorithms. Please see the Summary Consideration. | | | |
| BPA | | ☑ | The impact of load growth for Network Integration Transmission Service should be included in R11.2.<br><br>The "five years or longer in duration" language should be removed from R11.5. due to the fact that this element of Order 890 is only to be implemented by a Transmission Service Provider (TSP) once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day |

| Question #2 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those existing Customers who have not yet been required to commit to five years of service to retain their roll-over rights. |
| **Response:** The SDT modified the format of the requirement so that it requires the use of an algorithm rather than requiring the use of 'inputs'. In the revised requirement, 'Firm Network Integration Transmission Service' is one element in the Firm ETC algorithm, defined as the firm capacity reserved for network integration transmission service reserved on Posted Paths that serve as interfaces with other Transmission Service Providers.<br>The SDT has removed the timeframe noted in R11.5. (See the algorithm in R8 in the revised standard- the revision is in the definition of Firm Roll Over Rights.) | | | |
| Duke Energy | | ☑ | R11.4 should read as follows: The impact of Firm Point to Point Transmission Service adjusted for Post-backs.<br>R11.5 should read as follows: The impact of maintaining roll-over rights for Long-Term Firm Transmission Service contracts.<br>R11.6 should be deleted or replaced with more specific details of what Ancillary Services impacts are to be considered.<br>R11.7 should be deleted, since this is now included in R11.4 above.<br>R11.8 should be deleted or replaced with more specific details of how counterflows should be included.<br>R11.9 should read as follows: The impact of any other services, contracts, or agreements not specified above using transmission that serves Native Load or Firm Network Integration Transmission Service, adjusted for Post-backs.<br>R14.3 should read as follows: The impact of Non-Firm Point to Point Transmission Service, with adjustments for Post-backs.<br>R14.4 should be deleted or replaced with more specific details of how counterflows should be included.<br>R14.6 should be deleted, since this is now included in R14.3 above. |
| **Response:**<br>The SDT incorporated the intent of the R11.4 suggestion by changing, 'Firm Point to Point Transmission Service' to 'Firm capacity reserved for confirmed Point-to-Point Transmission Service'.<br><br>The SDT incorporated the intent of the R11.5 suggestion by changing the requirement so that instead of 'determining the impact of maintaining roll-over rights' the revised standard requires use of an algorithm to calculate ETC for Firm Commitments - and one element in the algorithm is 'Firm Roll-over Rights' – defined as the 'capacity reserved for roll-over rights for Firm Transmission Service contracts . . . '<br><br>The SDT incorporated the intent of the R11.7 through R11.9 in the revisions made to modify what had been R11.9 – in the revised standard, the algorithm for calculating Firm ETC has an element called, '$OS_F$' – defined as the capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other | | | |

| Question #2 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| firm adjustments to reflect impacts on other Posted Paths as described in the ATCID. With this revision, the intent of what had been R11.6, R11.7, R11.8 and R11.9 have been addressed in the determination of $OS_F$.<br>The SDT modified MOD-001 – Available Transfer Capability to include specific requirements that (R 4 and R5) that specify how to determine the impact of counterflows when determining firm and non-firm ATC. In addition, the revisions to MOD-001 require the Transmission Service Provider to prepare a document (called ATCID) that includes information about the methodology used to determine ATC, and one of the new requirements states that the Transmission Service Provider must document, in its ATCID, how it accounts for counterflows.<br><br>R14.3 – The SDT incorporated the intent of the suggestion by changing, 'Non-Firm Point to Point Transmission Service' to 'Non-Firm capacity reserved for confirmed Point-to-Point Transmission Service'.<br><br>R14.4, R14.6 - in the revised standard (see R9), there is an algorithm for calculating Non-Firm ETC with an element called, '$OS_{NF}$' – defined as the capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts on other Posted Paths as described in the ATCID. With this revision, the requirements that had been included in R14.4, R14.5, and R14.6 are addressed in the determination of $OS_{NF}$. | | | |
| Entergy | | ☑ | R.12 is part of ETC for Firm ETC and R15 is adjustment to the Non-Firm ETC which is similar to post back of capacity, therefore, these should be included as sub bullets under R11 and R14 respectively. |
| **Response:**<br>The SDT could not find a reliable approach to specifying how this should be implemented and the requirement (R12) was removed. | | | |
| IESO | | ☑ | We feel that R11.1, R11.2, R11.6 and R14.1 leave room for double counting of components that shold have been taken care of by TRM and CBM. Further, we do not understand why the CBM component is excluded from R13. If the omission is based on the rationale that CBM could be offered as non-firm ATC, then wouldn't TRM be treated in the same manner? |
| **Response:** The drafting team made significant modifications to this standard to eliminate opportunities for double counting – and one of the significant modifications was to formalize the algorithms for calculating ETC. The revised standard is more specific, and instead of requiring the Transmission Service Provider to determine the 'impact of firm ETC's' the revised standard includes the following algorithm for calculating Firm ETC and includes a definition of each of the elements used in the algorithm:<br><br>$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$<br><br>R11.1, which addressed native load commitments, was removed from the standard.<br>R11.2 was which focused on the 'impact' of Firm Network | | | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| IRC | | ☑ | We feel that R11.1, R11.2, R11.6 and R14.1 leave room for double counting for components that shold have been taken care of by TRM and CBM. |
| **Response:** The requirement language was modified such that these comments are not applicable to the current version of the standard. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| ISO NE | | ☑ | We suggest rephrasing R11 and R14 so that it also states that: "The TSP shall determine the impact of firm ETCs based on the inputs listed below. If any of the inputs listed below refer to a product or service that is not contained in the TSP's FERC-approved Tariff, the TSP shall document this fact in their ATCID and the value of such input(s) in the ETC calculation shall be considered to be zero MW."<br><br>The wording of 11.8 and 14.4 imply that the TSP MUST include the impact of counterflow. We do not agree that the impact of counterflow MUST be considered. It should up to the TSP as to if, when and how counter flow is considered. The requirement should be worded to allow for that flexibility and require that the TSP document how it is considered. |
| **Response:** The suggested language for ETC was not adopted since the standard allows for each ATCID to document how the components are determined. If the component is not applicable due to the TSP tariff, the ATCID can describe that and the suggested language is not required to be in the standards for that to occur.<br><br>The DT is following FERC guidance on establishing consistency and defines default treatment of counterflow in the standard. If a TSP has reliability reasons for doing something different, they can include that description in their ATCID. | | | |
| MEC<br>MRO | | ☑ | 1. R11 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm existing transmission committements based on an appropriate level of the following inputs."<br>2. Existing transmission commitments should not be listed in capatalized letters unless a definition is going to be developed for the NERC Glossary. |
| **Response:** The DT believes "appropriate level" is too vague to be measured objectively. When determining ETC, impacts of all Firm commitments should be noted.<br>ETC is capitalized because it is an acronym, and we have added a definition. | | | |
| FirstEnergy | ☑ | | However the term "Post-backs" is industry jargon and should be replaced with the term "reinstatement" to add clarity., |
| **Response:** We have included the term postback and it is intended that NAESB work to clarify what is included in postbacks. | | | |
| MEC Trading | ☑ | | |
| PSC SC | ☑ | | |
| SCS | ☑ | | |

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area.

**Summary Consideration:** Many stakeholders who responded to this question disagreed with the proposed applicability. The SDT has redrafted the standard after significant study of the functional model to address these concerns and the revised standard does not have any requirements applied to either the Planning Coordinator or the Reliability Coordinator.

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| MEC Trading | | | This is very difficult because the functional model seems to be very specific, but roles within a utility are not so clearly defined. |
| **Response:** The SDT agrees that it can be difficult to apply the functional model to a specific entity. | | | |
| MRO | | ☑ | The MRO believes that the Functional Entity as provided in A.4. should not be qualified, for example, the MRO recommends that A.4. just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider. |
| **Response:** Per the guidance provided by the NERC standards staff, the 'Applicability' section of the standard should always identify any limitations associated with the applicability. MOD-028 only applies to entities that use the network response methodology of calculating ATC. | | | |
| MEC | | ☑ | The Functional Entity as provided in A.4. should not be qualified, for example, A.4. should just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider. |
| **Response:** Per the guidance provided by the NERC standards staff, the 'Applicability' section of the standard should always identify any limitations associated with the applicability. MOD-028 only applies to entities that use the network response methodology of calculating ATC. | | | |
| SERC ATCWG | | ☑ | The applicability section needs clarification. Referencing R4 and R5, they should apply only to those entities performing the function. The standard should not require the calculations be made by the PC and RC, but should be applicable to the designated entitiy performing these calculations . The designated entity must be specified as a requirement in this standard. For example: The TSP, PC and RC must specify and agree to the entity that performs this function in the TSP's ATCID as required in MOD 1. The current revision of MOD-001 states the following requirement as R1: "Each Transmission Service Provider, and its associated Planning Coordinators and Reliability Coordinators, shall agree upon and implement one or more of the ATC methodologies specified in Reliability Standard MOD-028, MOD-029, and MOD-030 for use in determining Transfer Capabilities of those Facilities under the tariff administration of that Transmission Service Provider." The requirements of MOD-0028 should refer to the Designated Entity specified through this requirement. The following are examples of how this would be implemented in the standard:<br>B. Requirements<br>R4. Each Designated Entity shall ensure that the Total Transfer Capability (TTC) for each of its |

| Question #3 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Transmission Service Provider's POR to POD Paths is calculated and up-to-date for use within the Transfer Capability time horizons specified in MOD-001 R2.<br>R5. Prior to calculating TTC, each Designated Entity shall update the following components of the base case power flow model it uses to calculate TTC for the time horizon being studied: |
| **Response:** The SDT has redrafted the standard after significant study of the functional model to address these concerns.<br>The drafting team revised MOD-001 — Available Transfer Capability so that R1 has been deleted from the revised set of standards, and MOD-001 no longer has any requirement assigned to either the Planning Coordinator or the Reliability Coordinator.<br>The revised MOD-028 does not have any requirements applied to either the Planning Coordinator or the Reliability Coordinator.<br>The Functional Entity may delegate tasks but the responsibility remains with the Registered Entity, so adding a new term and assigning requirements to that new 'function' is not an acceptable modification. The standard must identify the same functional entities that register in NERC's compliance registry. | | | |
| APPA | | ☑ | As stated in comment no. 1, TTC is directed to be handled in the FAC series Standards. Therefore the Applicable Functions are incorrect. |
| **Response:** MOD-028, MOD-029 and MOD-030 include the appropriate requirements for total transfer capability as they apply to each ATC methodology. All requirements that were included in FAC-012 and FAC-013 are now incorporated into the MOD standards. | | | |
| BPA | | ☑ | "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority. |
| **Response:** MOD-028 and the ATC calculations are limited to the 13 month timeframe and Planning Coordinator is no longer included in the standard. | | | |
| IESO<br>IRC | | ☑ | The Planning Coordinator and Reliability Coordinator do not calculate ATCs. We suspect the reason that they are included in the applicability section is for their role in determining TTC. However, their roles are incorrectly stated in the applicability description. |
| **Response:** The SDT has redrafted the standard after significant study of the functional model to address these concerns.<br>The revised MOD-028 does not have any requirements applied to either the Planning Coordinator or the Reliability Coordinator. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| HQT<br>NPCC WG | ☑ | ☑ | We agree with the entities listed. However, the description of the applicability for the PC and RC are not valid. The PC and RC provide input to ATC calculations, but they do not calculate ATCs. Suggest replacing 'ATCs' with 'TTCs' in the description of Requirement 4.1 and 4.2. |

| Question #3 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Also, the language in these Applicability descriptions should be the consistent between MOD-028 and MOD-029. |
| **Response:** The SDT has redrafted the standard after significant study of the functional model to address these concerns. The revised MOD-028 does not have any requirements applied to either the Planning Coordinator or the Reliability Coordinator.<br>The descriptive language in the applicability section of MOD-028 was already used in MOD-029 and MOD-030. | | | |
| ISO NE | ☑ | ☑ | We agree with the entities listed. However, the description of the applicability for the PC and RC are not valid. The PC and RC provide input to ATC calculations, but they do not calculate ATCs. Suggest replacing 'ATCs' with 'TTCs' in the description. |
| **Response:** The SDT has redrafted the standard after significant study of the functional model to address these concerns. The revised MOD-028 does not have any requirements applied to either the Planning Coordinator or the Reliability Coordinator. | | | |
| Entergy | ☑ | | Applicability section correctly includes entities to whom this standard is applicable. However, in requirements the entities are not qualified as ".....that uses the Network Response method....". Appropriate adjustments to the requirements should be made throughout this standard. |
| **Response:** This comment has been addressed in the applicability section of the standard; therefore, the requirements only pertain to users of this method. | | | |
| FirstEnergy | ☑ | | MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once, eliminate duplication, and simplify the applicability sections of MOD-028, 029, and 030. |
| **Response:** The DT began with this approach but the resulting standard was very large and confusing as to what requirements a TSP had to comply with. We believe that by separating the standards to each cover a different methodology the standards will be easier to follow and enforce. | | | |
| Duke Energy | ☑ | | |
| PSC SC | ☑ | | |
| SCS | ☑ | | |

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

**Summary Consideration:** The majority of commenters agreed that there was no need for additional elements. There were some suggestions to refine or reorganize the sub-requirements, and the drafting modified R5 so that rather than specifying that the model has to be updated for the time horizon being studied – in the revised standard there are several requirements that address the modeling requirements - one general requirement (R2), and two additional requirements. One of the new requirements specifies, in greater detail, certain data that must be brought up to date in the model used for determining TTC for the intra-day and next-day time periods (R3); and another requirement for data that must be updated for determining TTC for time periods beyond the next day (R4).

| **Question #4** | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The requirements in R5 have already been mandated, correctly, in the FAC and other MOD models. To repeat those requirements in this standard will confuse the industry and make it impossible the maintain a workable compliance program for several standards. |
| **Response:** The requirements related to determining TTC for use in ATC will now be solely located within the MOD standards and the FAC-012 and FAC-013 standards will be retired. | | | |
| Entergy | | ☑ | If intent of R5.4 and R5.5 is to update power flow models to include all known outages, R5.6 and R5.7 should be merged with R 5.4 and R5.5 to include planned and unplanned outages. |
| **Response:** The DT modified the standard so that the intent of requirements R5.4 and R5.5 have been merged as suggested. In the revised standard, the merged requirement is organized by 'time period' and appears in R3.1.1, R3.2.1, R4.1.1 and R4.2.1.<br>Because 'unplanned outages' (identified in the posted version of the standard as R5.4 and R5.5) can't be predicted, these were removed from the revised standard. | | | |
| FirstEnergy | | ☑ | R 5.11 requires inclusion of the data provided by adjacent Transmission Service Providers and any other TSP with which coordination agreements have been executed; however, this standard does not include a requirement for adjacent TSPs to provide this data nor for executing coordination agreements with other TSPs. |
| **Response:** The requirement already exists in MOD-001, which is the 'parent' to this standard. This was intentionally left somewhat open because NERC cannot force coordination agreements to occur. We want to enforce that to the extent they are in place, that data MUST be utilized. | | | |
| IRC<br>IESO | ☑ | ☑ | While the component list appears to be complete, we find it difficult to keep track of or understand the rationale behind putting this requirement in this standard, while being uncertain of what changes are to be made to FAC-012 and -013. If those parts of FAC-012 and -013 that relate to TTC calculation are to be absorbed in this standard, then we'd think that having R5 (and R6) alone may not be |

| Question #4 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | sufficient. On the other hand, if FAC-012 and -013 are to remain as is or be moved to other standards, then we do not see the need to replicate partical requirements in MOD-028.<br>Note that the supplementarty SAR indicates that: "Specifically, the following Standards may be modified, transferred to NAESB or retired:<br>FAC-012 Transfer Capability Methodology<br>FAC-013 Establish and Communicate Transfer Capabilities<br>The SDT needs to be more specific and certain of its direction on these two standards to help the industry better understand and track changes. |
| **Response:** The requirements related to determining TTC for use in ATC will now be solely located within the MOD standards and the FAC-012 and FAC-013 standards will be retired. | | | |
| ERCOT | ☑ | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| MEC Trading | ☑ | | A consistent way of modeling all of the things listed in R5 should be clearly identified within the standard (partial path reservations, conditional firm service, outages that last 1 day for a monthly model, etc.) |
| **Response:** The drafting team has added detail to clarify where possible. Please see the Summary Consideration. | | | |
| HQT | | ☑ | |
| Duke Energy | | ☑ | |
| ISO NE | | ☑ | |
| MEC | | ☑ | |
| MRO | | ☑ | |
| NPCC WG | | ☑ | |
| PSC SC | | ☑ | |
| SCS | | ☑ | |
| SERC ATCWG | | ☑ | |

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

**Summary Consideration:** The drafting team received very few comments in response to this question, and there was no consensus amongst those who did comment. The Drafting Team discussed this issue in an attempt to define specific requirements to ensure consistent implementation. Several different approaches were discussed. However, talking through examples, it was determined that each implementation would have a detrimental impact on either reliability or Open Access. Therefore, this requirement has been removed. This shall serve as a singe response to all opinions offered.

| Question #5 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The statement as written will impair the operational flexibility of the BES. Any path or network or flowgate that has a rating higher at its POR than the rating of a generator connected at the same POR would limit the transfers at that POR to the generator size. The SDT does not want that. The only time this will be appropriate is when the generator is connected by a radial generator-tie and no other transaction from the system will use this node as the POR. |
| Duke Energy | | ☑ | The Transmission Service Provider shall limit the modeling of all Transmission Reservations from a specific generating plant to not exceed the modeled rating of all generators at that plant. Transmission Reservations should be allocated first to DNR's and the remainder allocated proportionately up to the modeled plant rating. |
| Entergy | | ☑ | The language of R12 does not directly address the intent of Order 890 paragraph 245. It does not provide clear instructions for treatment of multiple reservation from a POR (generator) other than limiting the impact to name plate rating. We suggest that a uniform method, or alternate methods be included for treating these reservations to address Order 890 paragraph 245. |
| SCS | | ☑ | We interpret the intent of paragraph 245 to imply that a generator should not be modeled at a level exceeding its maximum capability. With this interpretation, service could be granted up to the capability of the generator for each different POD. This is not allowed as R12 is currently drafted. |
| ERCOT | ☑ | ☑ | See IRC comments submitted by Charles Yeung. |
| MEC | ☑ | ☑ | The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests and show how the Transmission Service Provider than reviews the impacts to |

| Question #5 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | meet the requirement. |
| MRO | ☑ | ☑ | The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests and show how the Transmission Service Provider than reviews the impacts to meet the requirement. |
| FirstEnergy | ☑ | | However, the phrase "not exceed" can be replaced with the word "the" since the term "limiting the total impact" is synonomous. |
| MEC Trading | ☑ | | The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. This appears to make unit specific service of less value then service that lists a control area for redirecting that service. |
| PSC SC | ☑ | | |

6. Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

**Summary Consideration:** Requirements related to TTC as they relate to ATC calculations have been incorporated in MOD-028, MOD-029 and MOD-030 and FAC-012 and FAC-013 will be retired. The drafting team is transferring all requirements dealing with public posting to NAESB. Changes were made to the standard to address the remaining comments.

| Question #6 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | Requirements R1 through R9 should be in the FAC series Standards. The TTC Standards do not address any of the reliability issues that would have been address in FAC-012 and FAC-013, if they had not been written as a fill-in-the-blank standard. The Regional Procedures for determining TTC that are requested in the existing FAC-012 would not have been written as proposed in MOD-028, 029, or 030. |
| **Response:** Requirements related to TTC as they relate to ATC calculations have been incorporated in MOD-028, MOD-029 and MOD-030 and FAC-012 and FAC-013 will be retired. | | | |
| BPA | | ☑ | R2. -- For system security reasons, the contingency list details should not be publicly available. Identifying the most critical contingencies publicly could make them a target and thus reduce system reliability. This information should only be shared with those entities demonstrably impacted by such limiting contingencies. |
| **Response:** The drafting team has been working cooperatively with NAESB and all requirements dealing with public communication will be addressed by NAESB business practices. | | | |
| Duke Energy | | ☑ | R2, R3, R8 and R16 are "communications" in nature and should be removed from NERC requirements and should be put into NAESB business practice standards where the communications requirements can be justified.<br><br>Need to re-word the following requirements:<br>R4. The Planning Coordinator, Reliability Coordinator or Transmission Service Provider shall ensure that the Total Transfer Capability (TTC) for each of its Transmission Service Provider's POR to POD Paths is calculated and up-to-date for use within the Transfer Capability time horizons spedified in MOD-001 R2.<br><br>R5. Prior to calculating TTC, the Planning Coordinator, Reliability Coordinator or Transmission Service Provider shall ensure the following components of the base case power flow model used to calculate TTC for the time horizon being studied are updated:<br>R5.6. Unplanned transmission system Element outages, or unplanned returned to service.<br>R5.7. Unplanned generation resource outages, or unplanned returned to service.<br>R5.10. Appropriate Firm Transmission Service Reservations, to eliminate netting of flows to avoid reliability concerns with associated reservations not being scheduled. |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | R6. The Planning Coordinator, Reliability Coordinator or Transmission Service Provider shall follow these steps in determining the TTC for each path specified:<br>R7. Each Planning Coordinator and Reliability Coordinator that calculates TTC shall provide its Transmission Service Provider with the TTC for each of the specified paths. |

**Response:**

R2, R3, R8, R16 - The drafting team has been working cooperatively with NAESB and all requirements dealing with public communication will be addressed by NAESB business practices.

R4 - which required the Planning Coordinator and Reliability Coordinator to ensure that TTC for each of the Transmission Service Provider's paths was calculated according to a schedule has been deleted. In the revised standard, the drafting team uses the term, 'Posted Path' rather than referring to the paths as 'POR to POD Paths'. The revised standard assigns the Transmission Operator the responsibility for calculating TTC (R6) at specified intervals unless otherwise requested by the Transmission Service Provider – this supports the intent of your suggestion.

R5 – the requirement was reassigned so that it applies only to the Transmission Operator and the requirement was subdivided into several requirements with a greater focus on the data updates that are needed for calculating TTC for different time periods – the modeling updates required for calculating TTC for for intra-day and next-day periods differ from the modeling updates required for calculating TTC for use during time periods beyond the next day. This supports the intent of your suggestion.

R5 and R7 – the suggestions to add the Transmission Service Provider to the list of functional entities responsible for calculating TTC was not adopted. The drafting team modified this standard, based on stakeholder comments and a more thorough review of the Functional Model, and determined that the Transmission Operator should be responsible for calculating TTC.

R5.6 – the suggestion to enhance the requirements for modeling 'unplanned outages' was not adopted as proposed – modeling 'unplanned outages' is problematic in certain time periods – instead the drafting team merged the language from R5.4 through R5.7 which addressed various types of generation and transmission outages into a single sub-requirement that says, " Expected generation and transmission outages, additions, and retirements' This set of changes supports the intent of your suggestion.

R7 – the suggestion to qualify the subset of Transmission Planners and Reliability Coordinators that must provide the Transmission Service Provider with TTCs was not adopted because the responsibility for determining TTCs has been assigned to the Transmission Operator and the applicability section of the standard already states that the requirements in the standar are only applicable to those Transmission Operators who use the Area Interchange Methodology to calculate TTCs for Posted Paths.

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | |
| Entergy | | ☑ | From R5.11, language "with which coordination agreements have been executed" should be struck.<br>In R6.3, "interfaces" should be changed to ties/interconnections.<br>In R7, "each of the specified' should be struck and "idenfied in R3" should be added after paths.<br>From R11.5, the language "five years or longer in duration…..renewal" should be struck and "as applicable" be added after contracts. |
| **Response:** The drafting team did not understand why the language in 5.11 should be modified – the drafting team did add a qualifying phrase (provided that data can be associated with Facilities that are explicitly represented in the Transmission model) to clarify the reason why this data is needed<br><br>The drafting team modified the 'process' (R6) that is used to calculate TTC and the sub-requirement R6.3 was modified as follows (R7 in the revised standard) using the suggested word, 'ties' rather than 'ties/interconnections':<br>- The sum of the incremental Transfer Capability and the impacts of Firm Transmission Service that were included in the study model, or<br>- The sum of Facility Ratings of all ties comprising the Posted Path.<br><br>R7 – the drafting team modified this requirement so that it is assigned to the Transmission Operator and links with the other 'ATC-related' standards by referencing 'Posted Paths.'<br>R11.5 – the suggestion to remove the phrase, 'five years or longer in duration' was removed from the standard but the phrase, 'as applicable' was not added as this is ambiguous. | | | |
| ERCOT | | | See IRC comments submitted by Charles Yeung. |
| **Response:** See the response to IRC's comments. | | | |
| HQT<br>ISO NE<br>NPCC WG | | ☑ | R1: MOD-028 requires 'a list', MOD-029 requires 'a description'. The language for this requirement between these two MODs should be consistent.<br>R2: This list of contingencies could contain critical infrastructure information. The phrase "consistent with CEII policies" should be added to the end of this requirement.<br>R6.1: The intent of the text of Requirement 6.1 in MOD-028 and MOD-029 seems to be the same. If the intent is the same, the language should be the same. |
| **Response:**<br>R1 and R2 – R1 was revised and in the revised standard the contingencies and assumptions need to be identified in the Transmission Service Provider's ATCID. There are no posting requirements in the standard – the entities that receive the information are those that need the information for reliability.<br>R6.1 – while both MOD-028 and MOD-029 include a 'process' for determining TTC, the processes are different. | | | |
| IESO<br>IRC | | ☑ | We have a question on R13 with respect to the omission of CBM (see our comments under Q2). Further, in R15, we do not understand what would be the items that are "by the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC" when |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | increasing non-firm ATC. |
| **Response:** With regard to R13, FERC indicated that non-firm should not include CBM. R15 was describing the typical release of unused Firm service that will increase non-firm ATC. The algorithms added to the standard should clarify these requirements. | | | |
| SCS | | ☑ | R5.11 Comments. It may not be feasible to include all data from neighboring systems (e.g. PC or RC may not be able to incorporate all Special Protection schemes in a base case for TTC calculation). Also, the timeframes for which the values are being calculated may not allow for the incorporation of this data. |
| **Response:** The standard was revised and this requirement is now assigned to the Transmission Operator. In the revised standard, not all data needs to be updated for all time periods for which TTC must be determined. | | | |
| SERC ATCWG | | ☑ | See comments in Question 3. |
| **Response:** See response to SERC ATCWG Question 3. | | | |
| MEC | | ☑ | 1. For R1, R2, R4, R5, R6, and R7, the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard.<br><br>2. R6.2 and R6.3 use "first contingency" which implies that the only planning criteria to be used is first contingency outages. The TTC must be based upon the appropriate planning criteria whatever that is. The references to first contingency should be made more generic.<br><br>3. R3, R8 and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration.<br><br>4. R11 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropraite level of " the following inputs.<br><br>5. R14 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the area to maximize the non-firm offerings in the operating horizon. I suggest wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC." |
| **Response:**<br>1. The reliability entities have been modified in the standard based on stakeholder comments and a more thorough review of | | | |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| the Functional Model. The revised standard does not assign any requirements to the Planning Coordinator or the Reliability Coordinator – but does assign responsibility for determining TTC to the Transmission Operator.<br>2. The language in R6 has been modified so that the term, 'first contingency', is not used.<br>3. The DT agrees, all publishing of information will be handled by NAESB - R<br>4. The term, 'appropriate' is ambiguous - the SDT did modify the language to be more clear. The revised standard includes an algorithm for the determination of ETC.<br>5. The revised language in the standard does not preclude the use of meter-data to increase accuracy of the calculations or the modeling. | | | |
| MRO | | ☑ | 1. The MRO believes that for R1, R2, R4, R5, R6, and R7, the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. 2. R6.2 and R6.3 use "first contingency" which implies that the only planning criteria to be used is first contingency outages. The TTC must be based upon the appropriate planning criteria whatever that is. The references to first contingency should be made more generic. 3. R3, R8 and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration. 4. R11 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an approprite level of " the following inputs. 5. R14 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the MRO to maximize the non-firm offerings in the operating horizon. The MRO suggests wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC." |
| **Response:** 1. The reliability entities have been modified in the standard based on stakeholder comments and a more thorough review of the Functional Model. The revised standard does not assign any requirements to the Planning Coordinator or the Reliability Coordinator – but does assign responsibility for determining TTC to the Transmission Operator.<br>2. The language in R6 has been modified so that the term, 'first contingency', is not used.<br>3. The DT agrees, all publishing of information will be handled by NAESB - R<br>4. The term, 'appropriate' is ambiguous - the SDT did modify the language to be more clear. The revised standard includes an algorithm for the determination of ETC.<br>5. The revised language in the standard does not preclude the use of meter-data to increase accuracy of the calculations or the modeling. | | | |
| MEC Trading | | ☑ | This is a fill-in-the-blank standard. |
| **Response:** The revised language in the standard has attempted to eliminate the 'fill-in-the-blank' aspects that existed. | | | |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSC SC | ☑ | | |
| FirstEnergy | ☑ | | |

7. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

**Summary Consideration:** The majority of commenters did not see any conflicts.

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| HQT | | ☑ | We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets. |
| **Response:** The DT recognizes that some of the ETC components may be zero. The applicable entities should identify and explain the zero ETC components as part of complying with the standard. Note that the standard's applicability has been modified, and the revised standard is only applicable to those Transmission Operators that use the Area Interchange Methodology to calculate TTCs for Posted Paths – and to those Transmission Service Providers that use the Area Interchange Methodology to calculate ATCs for Posted Paths. | | | |
| IESO | | ☑ | However, please note that some markets do not offer physical transmission services and hence some of the requirements in this standard do not apply to these entities. |
| **Response:** Note that the standard's applicability has been modified, and the revised standard is only applicable to those Transmission Operators that use the Area Interchange Methodology to calculate TTCs for Posted Paths – and to those Transmission Service Providers that use the Area Interchange Methodology to calculate ATCs for Posted Paths. | | | |
| IRC | | ☑ | No, but please note that some markets do not offer physical transmission services and hence some of the requirements in this standard do not apply to these entities. |
| **Response:** Note that the standard's applicability has been modified, and the revised standard is only applicable to those Transmission Operators that use the Area Interchange Methodology to calculate TTCs for Posted Paths – and to those Transmission Service Providers that use the Area Interchange Methodology to calculate ATCs for Posted Paths. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| ISO NE | | ☑ | We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the services (e.g., the offering of firm point to point service, see R.11.4) to which these requirements apply are not offered by Transmission Service Providers that do not sell transmission service in advance of the physical flow of energy.For example, many or all items associated with firm and non-firm ETC would be zero in the markets administered by these TSPs. For example, over the Pool Transmission Facilities in New England, all capability is considered available to the market (i.e., the Total Transfer Capability) until real-time scheduling occurs. With the current arrangement of these proposed standards, the ATC Implementation Document would clearly document how the TSP complies with these standards, based on what services are offered through the Commission-approved tariff and/or market rules. |
| **Response:** The DT recognizes that some of the ETC components may be zero. The applicable entities should identify and | | | |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| explain the zero ETC components as part of complying with the standard. Note that the standard's applicability has been modified, and the revised standard is only applicable to those Transmission Operators that use the Area Interchange Methodology to calculate TTCs for Posted Paths – and to those Transmission Service Providers that use the Area Interchange Methodology to calculate ATCs for Posted Paths. | | | |
| NPCC WG | | ☑ | We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets. |
| **Response:** Note that the standard's applicability has been modified, and the revised standard is only applicable to those Transmission Operators that use the Area Interchange Methodology to calculate TTCs for Posted Paths – and to those Transmission Service Providers that use the Area Interchange Methodology to calculate ATCs for Posted Paths. | | | |
| MEC | | ☑ | |
| Duke Energy | | ☑ | |
| Entergy | | ☑ | |
| FirstEnergy | | ☑ | |
| MRO | | ☑ | |
| PSC SC | | ☑ | |
| APPA | ☑ | | See comment No. 1 |
| **Response:** See APPA response to comment No. 1. | | | |
| MEC Trading | ☑ | | No requirement for consistency |
| **Response:** The drafting team feels there are requirements for consistency in calculating ATC and TTC in the revised set of standards. | | | |
| SCS | ☑ | | R12 requires the TSP to limit the total impact of all Transmission Service from a "POR" (multiple generators) not a specific "generator" as written in Order 890. |
| **Response:** This requirement has been removed, see Summary Consideration of Question 5. | | | |

8. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

**Summary Consideration:** The SDT agrees with the comment regarding "Posted Path," and has changed the standards accordingly. The DT uses the term "post-backs" and it is expected that NAESB will defined the details of what is included in postbacks. Additionally, all aspects of publishing information have been removed from these standards and will be handled by NAESB.

| Question #8 | |
|---|---|
| **Commenter** | **Comment** |
| APPA | MOD-028 is very confusing and it will be difficult, if not impossible, to integrate into a Compliance program. The Compliance Monitor and the industry will have a very difficult time determining what needs to be accomplished to be compliant.<br>All of the Documents in this review have been written like a policy and this will not permit a Compliance Monitor to be able to determine if the Registered Applicable Function is conducting themselves in a manner that will meet the objectives of the Standards. |
| **Response:** The language of the standards has been revised such that the requirements are measurable. | |
| BPA | The ATC MODs (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide narrative descriptions of these methodologies.<br>The Applicability section 4.1. through 4.3. and R1., R3., R6. through R10., R13., and R16. should be clarified that ATC need only be calculated and posted for Posted Paths, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.<br>R11.7. and R14.6. -- Please define the term "Post-back". |
| **Response:** The drafting team revised each of the standards to improve their clarity.<br><br>The drafting team has adopted the term, 'Posted Path' as proposed and will post it with the revised standard.<br><br>The SDT modified the set of ATC standards to use the term, "Posted Path," throughout to improve consistency and clarity.<br><br>The DT uses the term "post-backs" and it is expected that NAESB will defined the details of what is included in postbacks. | |
| ERCOT | ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single |

| Question #8 | |
|---|---|
| **Commenter** | **Comment** |
| | Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area and there has been no reservation of transmission capacity in ERCOT.<br><br>Available Transfer Capability is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. The ERCOT Interconnection has already moved "beyond" ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therefore both ERCOT and SPP are notified when the DC Tie capability is reduced.<br><br>Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.<br><br>In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.<br><br>In the current and future ERCOT market design the method of calculating ATC, TTC and the use of CBM and TRM are not applicable to the ERCOT Region. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance. |
| **Response:** The SDT agrees that this is a concern – ERCOT may wish to submit a request for a Regional Difference. | |
| FirstEnergy | The standard should include specifics of methods for complying with the term "publicly available" such as posting on OASIS, a corporate web page, etc. (This concept is mentioned in all MOD-028, MOD-029, and MOD-030.) |

<table>
<tr><th colspan="2">Question #8</th></tr>
<tr><th>Commenter</th><th>Comment</th></tr>
<tr><td></td><td>R5.10 needs more clarity. While it provides leeway with respect to recognizing Firm Reservations, the term appropriate is subjective in nature and requires quidance on determing what is appropriate and what is not.</td></tr>
<tr><td colspan="2">Response: All aspects of publishing information have been removed from these standards and will be handled by NAESB. The DT agrees with the comment on 5.10 and has modified the standard accordingly – see the list of information the Transmission Service Provider must include in its Area Interchange Capability Implementation Document in the revised standard. The list of information that must be in that ATCID has been modified to include contractual obligations for allocation f TTC (R1.3).</td></tr>
<tr><td>IESO<br>IRC</td><td>Please see our comments on the Supplementary SAR. Also, as indicated under Q4, we are concerned with the lack of details and specific direction on treatment of FAC-012 and -013, and how changes to these two standards will be coordinated with the requirements in this standard (and MOD-029 and MOD-030).</td></tr>
<tr><td colspan="2">Response: The DT addressed this concern in the response to comments on the supplemental SAR. Many stakeholders indicated that the standards needed more specificity and the drafting team has made significant changes to all of the standards in this set to improve consistency and clarity.</td></tr>
<tr><td>MEC</td><td>The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The purpose in MOD-028-1 be revised to replace "uniform" with "transparent".</td></tr>
<tr><td colspan="2">Response: The DT modified all of the purpose statements in MOD-028, MDO-029 and MOD-030 to use the phrase, 'consistency and transparency'. The Purpose of MOD-028 was changed to: To increase consistency and transparency in the development and documentation of transfer capability calculations for short-term Transmission services performed by entities using the Area Interchange Methodology to support reliable system operations.</td></tr>
<tr><td>MEC Trading</td><td>This standard should be combined with MOD-30 and the requirements should be written to require consistency.</td></tr>
<tr><td colspan="2">Response: The DT disagrees. There is sufficient difference between the two methods to warrant separate standards.</td></tr>
<tr><td>MRO</td><td>The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The MRO recommends that the purpose in MOD-028-1 be revised to replace "uniform" with "transparent".</td></tr>
<tr><td colspan="2">Response: The DT modified all of the purpose statements in MOD-028, MDO-029 and MOD-030 to use the phrase, 'consistency and transparency'. The Purpose of MOD-028 was changed to: To increase consistency and transparency in the development and documentation of transfer capability calculations for short-term Transmission services performed by entities using the Area Interchange Methodology to support reliable system operations.</td></tr>
<tr><td>SCS</td><td>1. As drafted, it is not completely clear as to which of the requirements would apply to long-term planning and which requirements would not apply.<br>2. The group should consider how conditional firm will be treated with respect to ETC and the TTC calculation.<br>3. The reference in R12 to "nameplate" should be change to "maximum capability." Under certain conditions, the output of a generator can exceed the value of its nameplate.</td></tr>
<tr><td colspan="2">Response: MOD-028 as drafted does not apply to long-term planning. Language was added to the standard (R4.1) to clarify that the calculations of TTC are for time periods through 13 months. The evaluation of long-term service requests is</td></tr>
</table>

| Question #8 | |
|---|---|
| **Commenter** | **Comment** |
| addressed very prescriptively in each TSPs OATT; therefore to avoid any potential conflict MOD-028 only pertains to short-term transmission service requests. Additionally, as mandated by FERC Order 890, it is expected that long-term service requests be evaluated by the same criteria that a transmission owners use to plan their respective system.<br><br>Conditional Firm Service (hours based) should be treated as Firm ETC except in the time frames (horizons) that curtailment is probable. Conditional Firm Service (contingency based) should be treated as Firm ETC for all horizons; however, operationally it is expected that RCs will develop processes to curtail this service when the limiting contingency occurs. NAESB should develop business practices for the conversion of both types of long-term Conditional Firm Service(CFS) when sufficient short-term ATC is available to make all or a portion of the CFS service firm as described in FERC Order 890.<br><br>R12 has been removed from the Standard | |
| SERC ATCWG | Standard is not clear as to what applies to long-term timeframe and short-term timeframe.<br>Reference in R12 to generator nameplate should be changed to maximum capability since in some conditions the generator can exceed nameplate rating. |
| **Response:** The standard applies only to the short-term service horizon. Language was added to the standard (R4.1) to clarify that the calculations of TTC are for time periods through 13 months.<br>R12 has been removed from the Standard. | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a standard drafting team on March 17, 2006.

**Description of Current Draft:**

This is the first draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR with consideration of applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Respond to comments. | TBD |
| 2. Post revised standard for stakeholder comment. | TBD |
| 3. Respond to comments. | TBD |
| 4. Post for 30-day pre-ballot review. | TBD |
| 5. First ballot of standard. | TBD |
| 6. Respond to comments. | TBD |
| 7. Recirculation ballot. | TBD |
| 8. 30-day posting before board adoption. | TBD |
| 9. Board adoption. | TBD |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**

2. **Number:** MOD-008-1

3. **Purpose:** To promote consistent and transparent calculation of the maximum Transmission Reliability Margin (TRM) and supporting methodologies among Transmission Service Providers, Transmission Planners, and Transmission Operators to help ensure more accurate calculation of transfer capabilities.

4. **Applicability:**

   **4.1.** Transmission Planner.

   **4.2.** Transmission Operator.

   **4.3.** Transmission Service Provider.

   **4.4.** Reliability Coordinator.

   **4.5.** Planning Coordinator.

   **4.6.** Load-Serving Entity.

5. **Proposed Effective Date:** To be determined.

## B. Requirements

**R1.** The Transmission Planner, and Transmission Operator shall each document its TRM calculation methodology, and shall include all of the following in that methodology:

**R1.1.** Identification any of the following uncertainties used to calculate its TRM:

- Aggregate Load forecast error (not included in determining generation reliability requirements).
- Load distribution error.
- Forecast uncertainty in transmission system topology.
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch.
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve sharing requirements.
- Inertial response.

**R1.2.** A statement to confirm that it shall use the same assumptions in calculating TRM as those that are used in the transmission planning process for the appropriate time periods.

**R1.3.** The description of the method of allocation across paths.

**R1.4.** The identification of that TRM calculation used for the following time periods:

**R1.4.1.** Same day and real-time.

**R1.4.2.** Day-ahead and pre-schedule.

**R1.4.3.** Beyond the day-ahead and pre-schedule.

**R1.5.** If a Transmission Planner or Transmission Operator reserves zero (0) TRM in any time horizon, that Transmission Planner or Transmission Operator shall document in its TRM methodology the reason(s) why it did not reserve any TRM.

**R2.** Each Transmission Planner and Transmission Operator that reserves TRM shall document in its TRM Calculation Methodology (on each of its respective posted Contract Paths or Flowgates) each of the following components of uncertainty if used in calculating TRM and shall describe how that component is used to calculate a TRM value:

- Aggregate Load forecast error (not included in determining generation reliability requirements).
- Load distribution error.
- Forecast uncertainty in transmission system topology.
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch.
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve sharing requirements.
- Inertial response.

**R3.** The Transmission Planner and Transmission Operator shall only use the components of uncertainty from R1.1 to calculate TRM.

**R4.** The Load-Serving Entity shall not use the components of uncertainty from R1.1 to determine its CBM megawatt import requirement.

**R5.** At least once each year, the Transmission Operator shall calculate (in accordance with its TRM methodology) a TRM value for the following time periods (on each path or Flowgate) and provide these TRM values to its Transmission Service Provider(s):

**R5.1.** Same day and real-time.

**R5.2.** Day-ahead and pre-schedule.

**R6.** At least once each year, the Transmission Planner shall calculate (in accordance with its TRM methodology) a TRM value for the time period beyond the day-ahead and pre-schedule (on each path or Flowgate) and provide these TRM values to its Transmission Service Provider(s).

**R7.** Each Transmission Service Provider shall make its TRM calculation methodology publicly available.

**R8.** Each Transmission Service Provider shall make available (within seven calendar days) any underlying documentation, work papers and load flow base cases used to determine TRM for the Facilities within its service territory to adjacent requesting Transmission Service Providers and to any requesting transmission customer or Load-Serving Entity within its service area unless providing the information violates an applicable rule, regulation or confidentiality agreement prohibiting such disclosure or where release of the requested data would pose a security risk to the grid.

**R9.** Each Transmission Planner, Transmission Operator, and Transmission Service Provider shall provide its TRM calculation methodology and supporting documentation to the Reliability Coordinator and Planning Coordinator responsible for oversight of the Facilities for which the Transmission Service Provider offers service.

**R10.** Each Transmission Service Provider shall make publicly available (for each posted path or Flowgate) the TRM value for each of the following time periods:

**R10.1.** Same day and real-time.

**R10.2.** Day-ahead and pre-schedule.

**R10.3.** Beyond the day-ahead.

**R11.** If a Transmission Planner or Transmission Operator reserves capacity on its transmission system for use as TRM, then the associated Transmission Service Provider shall use TRM in its calculation of Available Transfer Capabilities (ATCs) or Available Flowgate Capabilities (AFCs).

## C. Compliance

To be added with next posting.

## D. Measures

To be added with next posting.

## E. Regional Differences

None identified.

## F. Associated Documents

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
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Please use this form to submit comments on the 1st draft of standard MOD-008-1 Transmission Reliability Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculations and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

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Transmission Reliability Margin (TRM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-008-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations. Please review the 'White Paper' and the proposed MOD-008 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☐ No

   Comments:

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☐ Yes

   ☐ No

   Comments:

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a “maximum uncertainty” to support the validity of a TRM value? If “Yes,” please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☐ No

Comments:

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If “Yes,” please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☐ No

Comments:

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If “Yes,” please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments:

# References to Transmission Reliability Margin in FERC Orders

## *From FERC Order 890*

***From Page 1045:***

**§ 37.6 Information to be posted on the OASIS**.
(viii) Transmission Reliability Margin or TRM means the amount of TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure, or such definition as contained in Commission-approved Reliability Standards.

***Starting on Page 164:***

### (4) Transmission Reserve Margin (TRM)

**NOPR Proposal**

266. Finally, the Commission proposed the development of reliability standards MOD-008 and MOD-009[173] that specify the uncertainties that TRM could be used to accommodate, which could include (1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, including intermittent resources, (6) automatic sharing of reserves, and (7) other uncertainties identified through the NERC reliability standards development process.

**Comments**

267. Most commenters agree that the existing definitions for TRM require clarification.[174] Commenters also agree that NERC should be required to develop clear standards for the determination of TRM, including specifying the criteria used in the determination of TRM.[175] PNM-TNMP supports the Commission's proposal, pointing out that the

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[173] The MOD-008 and MOD-009 reliability standards document regional TRM methodologies and procedures for verifying TRM values.

[174] E.g., Allegheny, APPA, EEI, EPSA, Exelon, LPPC, MidAmerican, NRECA, Northwest IOUs, NorthWestern, Occidental, Pinnacle, Powerex, PNM-TNMP, PPL, PJM, PPM, and WestConnect.

[175] Exelon recommends that the following factors should be the same for the planning process and ATC/AFC process to achieve consistency: base case flows, reservation impacts, TRM and CBM forecasted to occur simultaneously; counterflows; positive impacts resulting from reservations and generation dispatch; TRM for the same scenarios; and CBM.

implementation of the current NERC standards definition for TRM and CBM could result in its double-counting, which must be eliminated. APPA members in the Western Interconnection suggest that regional variations be permitted. They also note that the modeling methods used by WECC and its sub-regions may differ from those used in the Eastern Interconnection. For example, they contend that uncertainties associated with transmission maintenance schedules that are driven by hydro-production curves will seasonally affect TRM set-asides on certain transfer paths. PJM believes that the TRM methodology should be consistent at the regional reliability organization level. PJM also contends that TRM should be coordinated, exchanged and respected on external flowgates and that the concept of a maximum TRM, by percentage, should be adopted in the NERC standards.

268. Consistent with its position on CBM, TAPS proposes that TRM set-asides should be conditioned on inclusive reserve-sharing arrangements, with the reservations determined by the reserve-sharing group, subject to dispute resolution before the Commission (and, eventually, approval by joint planning groups).

269. PNM-TNMP suggests that the Commission consider definitions to include the following clarification taken from WECC procedures on ATC: "If the limitation on the use of TRM to 59 minutes would force a Transmission Provider to set aside unnecessary CBM on the same path as the TRM, that Transmission Provider may utilize the TRM beyond the 59 minutes."[176] PNM-TNMP states that this would allow the transmission provider to maximize the ATC by not needlessly setting aside twice the amount of transmission (TRM and CBM) than is necessary for reliability.

270. Nevada Companies argue that no new standards are required for TRM and that any further action would be burdensome. They explain that NERC has a well-established definition that does not require further clarification. In their view, all that is required is a complete statement, to be posted on OASIS, regarding the transmission provider's application of TRM. NERC comments that the existing reliability standards for TRM will be revised to require clear documentation of the calculation of TRM. It also adds that the revised standard will make various TRM components mandatory to achieve more consistency across methodologies.

271. Santee Cooper urges the Commission to ensure that service to native load and transmission system reliability will not be compromised as the Commission seeks greater levels of consistency in the calculation of ATC. It states that the Commission also must be cognizant of the importance of TRM in the provision of service to native load.

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[176] Citing WECC Rocky Mountain Operating and Planning Group, Determination of Available Transfer Capability within the Western Interconnection, June 2001, page 9, http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=getit&lid=1035.

**Commission Determination**

272. The Commission adopts the NOPR proposal and requires public utilities, working through NERC, to complete the ongoing process of modifying TRM standards MOD-008 and MOD-009. We understand that the standard drafting process is underway as a joint project with NAESB.

273. The Commission also adopts the NOPR proposal to establish standards specifying the appropriate uses of TRM to guide NERC and NAESB in the drafting process. Transmission providers may set aside TRM for (1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, (6) automatic sharing of reserves, and (7) other uncertainties as identified through the NERC reliability standards development process. Because load, facility loading and other uncertainties constantly deviate, we will not require that TRM set aside capacity be set at zero in the non-firm ATC calculation. In other words, we will not require transfer capability that is set aside as TRM to be sold on a non-firm basis. We find that clear specification in this Final Rule of the permitted purposes for which entities may reserve CBM and TRM will virtually eliminate double-counting of TRM and CBM.

274. We will not adopt PNM-TNMP's proposal regarding use of set aside transfer capability as TRM beyond 59 minutes, rather than converting it to CBM. Our proposal is to separate transfer capability set asides as either CBM or TRM without regard to duration of use of the set aside. Therefore, such a clarification is not necessary.

275. In addition, we direct public utilities, working through NERC, to establish an appropriate maximum TRM. One acceptable method may be to use a percentage of ratings reduction, i.e., model the system assuming all facility ratings are reduced by a specific percentage. This is a relatively simple method and, if adopted as the reliability standard's method, should not restrict a transmission provider from using a more sophisticated method that may allow for greater ATC without reducing overall reliability.

276. Because of the operational characteristics of the uncertainties that are to be accommodated using TRM, and their aggregate impact on reliable operation, we require each transmission provider to calculate, and allocate on the paths and flowgates, the aggregate TRM value for all LSEs within its area. We support NERC's plan to revise existing reliability standards for TRM to require clear documentation of the TRM calculation, as we expect the TRM value to be supported and fully transparent. In addition, we require each transmission provider to make available all underlying documentation, including work papers and load flow base cases, used to determine TRM, to any transmission customer and LSE within its control area, subject to a confidentiality agreement,[177] if necessary. We agree with Santee Cooper's comments that the

[177] The agreement may appropriately restrict the sharing of sensitive information with customer personnel that are involved only in transmission functions, as opposed to merchant functions.

Commission must ensure that service to native load and system reliability are not compromised. We believe that our requirement for public utilities to work through NERC satisfies such concerns.

277. With respect to the proposal to permit regional variations in the TRM calculation methodology, we reiterate our position stated above that any request for regional difference from the applicable reliability standards must take place through the NERC reliability standards development process. With respect to TAPS' proposal regarding reserve sharing groups, we clarify that, to the extent transfer capability is needed for transmission of shared reserves, this is included under TRM. However, as noted previously in the CBM discussion, we are not mandating the use of reserve sharing groups.

## ***From FERC Order 693***

***Starting on Page 305:***

### j. Documentation and Content of Each Regional Transmission Reliability Margin Methodology (MOD- 008-0)

1112. MOD-008-0 requires the development and posting of a regional methodology for TRM, which is transmission capacity that is reserved to provide reasonable assurance that the interconnected transmission network will remain secure under various system conditions. The Reliability Standard requires each regional reliability organization to: (1) develop and document a regional TRM methodology in conjunction with its members and (2) post on a website the most recent version of its TRM methodology.

1113. In the NOPR, the Commission identified MOD-008-0 as a fill-in-the-blank standard, proposing that because the regional methodologies had not been submitted, the Commission would not propose to approve or remand MOD-008-0 until the ERO submitted the additional information. The Commission expressed concern about the lack of: (1) clear requirements on how TRM should be calculated and allocated across paths and (2) consistent criteria and clarity with regard to the entity on whose behalf TRM had been set aside.

1114. The Commission requested comment in the NOPR on how TRM is currently calculated and allocated across paths, and what would be a recommended approach for the future.

### i. Comments

1115. APPA agrees that MOD-008-0 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until

NERC and the regional reliability organizations and regional entities develop the necessary regional methodologies and the Commission approves them.

1116. MISO adds that there should be a consistent framework to be followed by entities in determining TRM. It states that relevant MOD standards should be revised if such a framework is not clearly delineated. However, MISO cautions that a Reliability standard should not be used to address a perceived equity concern. MidAmerican also supports greater uniformity of TRM definitions and calculations, and proposes that a revised standard and/or new standards should encourage transparency with increased availability of information, consistent data input and certain modeling assumptions. International Transmission agrees and proposes that TRM consistency should be addressed either on a regional basis or on an Interconnection-wide basis.

1117. In response to the Commission's request for comments on the current calculation of TRM, and recommended approaches for the future, International Transmission provides a description of the MISO approach to TRM. International Transmission states that during the operating horizon (next 48 hours), TRM is limited to a reserve sharing component which only applies to flowgates that are not based on transmission outages (unit tripping and transmission outages are considered a double contingency). International Transmission states that the logic behind this approach is that there are fewer uncertainties in the operating horizon because schedules and market flows are known. International Transmission explains that during the planning horizon (next 48 hours), a two percent TRM component for uncertainty is used on all flowgates, including those requiring reserve sharing TRM. In addition, other assumptions regarding the sale of transmission service enter into the need for TRM to cover "uncertainties." In addition, International Transmission cautions that MISO's minimal two percent margin may not be sufficient for long-term planning horizon requests (i.e., over 13 months) if planning "assumptions" are not reasonable. International Transmission argues that MISO must also employ proper sensitivity studies to other system variables for a two percent margin to be sufficient. TRMs in the five to ten percent range are not necessarily unreasonable if a wide range of potential system operating conditions is not studied. Regardless of the ultimate approach adopted in future standards, International Transmission proposes that all entities follow a consistent framework when calculating TRM.

1118. MidAmerican responds with a discussion of its current approach to TRM calculation, which has been performed in accordance with MAPP-approved methodologies. MidAmerican states that these methodologies include an amount to allow for both the delivery of operating reserves and for uncertainties. Since delivery of operating reserves keeps the interconnected network in service, benefiting all market participants, MidAmerican contends that it is appropriate for TRM to include an amount to allow for the delivery of operating reserves. The allowance for uncertainty is calculated as a percentage of TTC required to protect reliability. All market participants benefit from the provision of an appropriate margin for uncertainty because the reliability of the interconnected network is maintained and service interruptions are reasonably minimized.

1119. With respect to applicable entities, APPA proposes the addition of two new functional entities. Specifically, APPA believes that NERC should expand the applicability section of MOD-008-0 to include planning authorities and reliability coordinators. APPA points out that these are the only entities that can evaluate the amount of error in their transfer capability predictions.

1120. ERCOT states that the Commission's concerns about TRM do not apply to ERCOT, because ERCOT has a balanced grid in which all transmission is firm, no transmission is reserved and there are no transmission paths.

**ii. Commission Determination**

1121. The Commission does not approve or remand MOD-008-0 until the ERO submits additional information. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO to modify MOD-008-0 through the Reliability Standards development process, as discussed below.

1122. Consistent with the NOPR proposal and Order No. 890, the Commission directs the ERO to modify standard MOD-008-0 to clarify how TRM should be calculated and allocated across paths or flowgates. We understand that the standards drafting process is underway as a joint project with NAESB. We agree with International Transmission, MidAmerican and MISO about the need for more uniformity and transparency in TRM calculation methodology and use, in order to eliminate potential reliability and discrimination concerns. Consistent with Order No. 890, the Commission directs the ERO to specify the parameters for entities to use in determining uncertainties for which TRM can be set aside and used, such as: (1) load forecast and load distribution error; (2) variations in facility loadings; (3) uncertainty in transmission system topology; (4) loop flow impact; (5) variations in generation dispatch; (6) automatic reserve sharing and (7) other uncertainties as identified through the NERC Reliability Standards development process. We find that clear specification in this Final Rule of the permitted purposes for which entities may reserve CBM and TRM will also virtually eliminate double-counting of TRM and CBM. Therefore, we direct the ERO to determine clear requirements regarding permitted uses for TRM through its Reliability Standards development process.

1123. We agree with the commenters that the percentage reduction of line rating can be one way to establish an appropriate maximum TRM if thermal considerations are the only limiting factors. While this is a relatively simple method, it ignores limitations relative to voltage or stability limitations which are the more typical reasons for transmission limitations. If adopted as the Reliability Standard method, it should not restrict a transmission provider from using a more sophisticated method that may allow for greater ATC without reducing overall reliability. However, we disagree with the use of an arbitrary percentage over a long time frame that is not based on either proven historical need or sensitivity studies that support that determination. Therefore, consistent with our OATT Reform Final Rule, we direct the ERO to develop requirements regarding transparency of the documentation that supports TRM determination**.**

1124. We agree with APPA that NERC should revise the applicability section of this standard to add planning authorities and reliability coordinators, and in addition, any other entities that may be identified in the Reliability Standards development process.

1125. Regarding ERCOT's statement that TRM does not apply to ERCOT, we reiterate our position that any request for a regional exemption from the applicable Reliability Standards must take place in the Reliability Standards development process.

1126. The Commission neither accepts nor remands MOD-008-0 until the ERO submits additional information. In the interim, compliance with MOD-008-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD-008-0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those proposed in Order No. 890. Accordingly, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process including: (1) clear requirements on how TRM should be calculated, including a methodology for determining the maximum TRM value, and allocated across paths; (2) clear requirements for permitted purposes for which TRM can be set aside and used; (3) clear requirements for availability of documentation that supports TRM determination and (4) expanding the applicability to add planning authorities and reliability coordinators and any other appropriate entity identified in the Reliability Standards development process.

### k. Procedure for Verifying Transmission Reliability Margin Values (MOD-009-0)

1127. MOD-009-0 requires each regional reliability organization to develop and implement a procedure to review TRM calculations and the resulting values determined by member transmission providers to ensure compliance with the regional TRM methodology.

1128. In the NOPR, the Commission identified MOD-009-0 as a fill-in-the-blank standard that requires each regional reliability organization to develop a procedure for review of TRM calculations and the resulting values. In the NOPR, the Commission stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD-009-0 until the ERO submits the additional information.

#### i. Comments

1129. APPA agrees that MOD-009-0 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations and regional entities develop the necessary regional methodologies and the Commission approves them.

**ii. Commission Determination**

1130. The Commission will not approve or remand MOD-009-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-009-0 satisfies the statutory requirement that a proposed Reliability Standard be “just, reasonable, not unduly discriminatory or preferential, and in the public interest.” Accordingly, the Commission neither approves nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD-009-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Abbey Nulph | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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Transmission Reliability Margin (TRM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-008-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations. Please review the 'White Paper' and the proposed MOD-008 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**2.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**3.** The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

☐ Yes

☒ No

Comments: "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority.

**4.** The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

☐ Yes

☒ No

Comments: R1.3. should read "The description of the method of allocation across Posted Paths or Flowgates" where Posted Path is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.
R2. -- The parenthetical statement should read "…on each of its respective Posted Paths or Flowgates..."
R5. and R6. -- The term "path" should be replaced with "Posted Path".
R10. -- The term "posted path" should be capitalized.

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments: Please clarify that the uncertainties listed in R1.1 may be used in TRM calculations (as opposed to being required to be used).

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☒ Yes

☐ No

Comments: While this methodology may be sufficient for several Transmission Service Providers (TSPs), it may not be for others. Therefore, use of this type of percentage should not be the only mechanism available for TSPs to determine TRM on their systems.

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments: BPA may not calculate TRM on some of its constraints due to uncertainty components being included in those constraints' TFC determinations. Therefore, a TRM of "0 MW" would be posted and documented, per R1.5. of MOD-008-1. Would this practice meet the intent of this standard?

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments:

**WECC MIC MIS ATC Task Force / Attendance Sheet**
**Attendance for WECC-Specific NERC Comments**

| NAME | Company | PHONE | E-MAIL | Present |
|---|---|---|---|---|
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| Brian Jobson | SMUD | 916-732-5939 | bjobson@smud.org | |
| Brian Weber | Pacifcorp | (503) 813-6444 | Brian.weber@pacificorp.com | |
| Casey Sprouse | Sr. Term Marketer | (509) 989-2081 | www.csprous@gcpud.org | |
| Charles Mee | Ca. DWP | (916) 574-0669 | cmee@water.ca.gov | |
| Chuck Falls | SRP | (602) 236-0965 | Chuck.Falls@srpnet.com | |
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| Terri M. Kuehneman | SRP System Operation | (602) 236-4392 | tmkuehne@srpnet.com | |
| Steve Tran | BP TX | | | |

Please use this form to submit comments on the 1st draft of standard MOD-008-1 Transmission Reliability Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Greg Rowland | |
| Organization: | Duke Energy | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculations and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Transmission Reliability Margin (TRM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-008-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations. Please review the 'White Paper' and the proposed MOD-008 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: It is unclear that the drafting team has addressed FERC's direction in paragraph 275 of Order No. 890 to establish appropriate maximum TRM. Perhaps the Standards Drafting Team should consider using the TPL standards requirements as a basis for bounding the maximum TRM value.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: This standard shouldn't be applicable to the Reliability Coordinator because this is a calculation methodology, and Reliability Coordination is a real-time role. Also, it is unclear which requirements of this standard apply to the Planning Coordinator. Unless specific roles in TRM determination are identified for the Reliability Coordinator and Planning Coordinator, they should be deleted from the Applicability section.

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☐ Yes

   ☒ No

   Comments: There is no requirement for coordination between the Transmission Operator and the Transmission Planner. Also, there should be a requirement that the TRM values should be equal to or lower than long-term TRM as you move closer to real-time and uncertainty diminishes.

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments:

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☒ No

Comments:

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: The explanation should describe how reliability is maintained in light of the uncertainties identified in R1.1

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☒ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments: The "make publically available" Requirements R7 and R10 are inappropriate for NERC standards. These are communications which should be in the NAESB standards.

Please use this form to submit comments on the 1st draft of standard MOD-008-1 Transmission Reliability Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| Organization: | Entergy Services Inc. | |
| Telephone: | 870-543-5420 | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| George Bartlett | Entergy Services Inc. | **SERC** | Transmission Owner |
| Jim Case | Entergy Services Inc. | **SEREC** | Transmission Owner |
| Ed Davis | Entergy Services Inc. | **SERC** | Transmission Owner |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Transmission Reliability Margin (TRM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-008-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations. Please review the 'White Paper' and the proposed MOD-008 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: There is no requirement applicable to Reliability Coordinator or Planning Coordinator. Therefore, MOD-008-1 should not be applicable to Reliability Coordinator and Planning Coordinator.

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☐ Yes

   ☒ No

   Comments: It is not clear if the intent of R2 is to document component of uncertainty on TRM on each posted path, or a general process to include impact of uncertainties in TRM methodologies is sufficient. The requirement should clarify such that the impact of uncertainties are included in TRM methodologies and not to document each component. R4 is written as a requirement for CBM methodology rather than for TRM methodology, it should be deleted or reworded.

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a “maximum uncertainty” to support the validity of a TRM value? If “Yes,” please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☒ Yes

☐ No

Comments: Study should include using historic data to determine impact of actual versus forecasted information on loading of transmission system components that are limiting the TTCs or TFCs.

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If “Yes,” please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☒ No

Comments: There is no technical justification of using 2 - 5% of Facility Rating as TRM. Since Facility Ratings are determined using conditions that are already worst case conditions, using additional safety factor results in underutilizing the transmission system. If uncertainties such as using first contingency conditions and using worst case scenarios for components that are used for ATC/AFC calculations already include uncertainties there should not be double counting of these uncertainties. If data can be supported by historic information, then only data should be used for setting aside TRM.

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: R1.5 tends to imply that all Transmission Planner and Transmission Operators must use TRM, unless they can justify not using it. On the contrary, those TPs and TOs who use TRM should justify its use as use of TRM results in lower ATCs due to uncertainties that may already be included in determining the components that are used for ATC calculations.

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If “Yes,” please explain your answer in the comments area.

☐ Yes

☒ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments:

Please use this form to submit comments on the 1st draft of standard MOD-008-1 Transmission Reliability Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Steve Myers | |
| Organization: | ERCOT | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☒ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☒ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area and there has been no reservation of transmission capacity in ERCOT.

Transmission Reliability Margin is defined as the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure.TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT.

Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, is divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.

In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.

In the current and future ERCOT market design the use of TRM is not applicable to the ERCOT Region. ERCOT does not have a synchronous connection with any other Control Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting TRM without the need for a Regional variance.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments: See IRC comments submitted by Charles Yeung.

Please use this form to submit comments on the 1st draft of standard MOD-008-1 Transmission Reliability Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☒ | 5 — Electric Generators |
| ☐ **SERC** | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

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| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
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| Phil Bowers | FirstEnergy Corp. EDPP | | |
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## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculations and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Transmission Reliability Margin (TRM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-008-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations. Please review the 'White Paper' and the proposed MOD-008 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**2.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**3.** The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

☒ Yes

☐ No

Comments:

**4.** The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments:

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments:

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☒ No

Comments:

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: This explanation increases tranparency in the calculation process which is desired by FERC.

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☒ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments: R4 is contained in the revised MOD-004-1 provided with this SAR packet as R14. R4 us a duplicate requirement and should be deleted from MOD-008-1. The request referenced in R8 shoud be required to be in writing as a means of formally documenting the request was made, received, and acknowledged.

Please use this form to submit comments on the 1st draft of standard MOD-008-1 Transmission Reliability Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

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**Group Name:**

**Lead Contact:**

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**Contact Segment:**

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| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Danielle Beaulieu | Hydro-Québec TransÉnergie | **NPCC** | 1 |
| Daniel Soulier | Hydro-Québec TransÉnergie | **NPCC** | 1 |
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## Background Information

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Transmission Reliability Margin (TRM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-008-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations. Please review the 'White Paper' and the proposed MOD-008 before answering the questions on the following pages.  Comments must be submitted by **June 24, 2007**.  You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team’s decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If “No,” please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission’s (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC’s directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If “No,” please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☐ No

   Comments:

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If “No,” please explain why in the comment area.

   ☐ Yes

   ☒ No

   Comments: Variations in facility loading should be back in the R1.1 list

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a “maximum uncertainty” to support the validity of a TRM value? If “Yes,” please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☐ No

Comments:

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If “Yes,” please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☒ No

Comments: TRM depends on system and path topology

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: TP or TO should only explain why it reserves non-zero TRM since it reduces the available capacity for the market

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If “Yes,” please explain your answer in the comments area.

☒ Yes

☐ No

Comments:
1. Variation of load (for daily, weekly, monthly and yearly ATCs)
2. Uncertainty about weather conditions (for daily, weekly, monthly and yearly ATCs)
3. Variation in facility loading (sufficient TRM should be maintained for deviations from load forecast due to balancing of generation within a control area )
4. Calculation Inaccuracies (Sufficient TRM should be assumed to account for the limitation of the TTC calculation method.)

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments: Are there different requirements on TRM for firm and non-firm ATC ?

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: We agree with combining the two standards, but the newly created standards contain quite a few more requirements than MOD-008-0 and MOD-009-0 taken together, and some of the requirements are duplicated (for example, R1 and R2). Also, some requirements are not clear as to who should be responsible, for example: there are conflicting yet sometimes duplicated requirements for documenting and calculating TRM. R1 and R2 hold the TP and TOP responsible for these tasks, yet R8 and R9 hold TSP responsible as well.

   There needs more clarity particularly in the accountability for documenting the methodology and in providing the supporting basis for determining TRM.

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: Most of the directives appear to be addressed. However, in view of the above comments, we expect the standards need more work so a revisit of this question is required.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: We do not think the standard clearly conveys the accountability of each of the responsibility entities well enough. Please see our comments to Q1 above.

   In addition, we feel that the entire set of MOD-001, -004, -008, -028, -029 and -30 lacks clarity in responsibility. For example, the RC and PC should not be responsible for calculating ATC. Why would they be included in the applicability section of some standards/requirements?

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

☐ Yes

☒ No

Comments: There are a number of duplicated requirements (e.g. R1 and R2 as noted above_) and there is no clarity on the accountability (e.g. R9). The standard needs to be reviewed and revised to more clearly convey the roles and responsibilities in accordance with the functional model and today's practice (on a functional entity basis).

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments: We do not believe any maximum values should be set as a standard. Individual TSP (or TP and TOP according to the proposed standard) should each determine the amount needed to cover transmission uncertainties, which may vary among systems. The validity of the calculated values can be assessed against the documented methodology and audit process.

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☒ No

Comments: We do not believe this approach duly addresses the various components of TRM which may change depending on the system conditions. However, we hold no position on individual entities who choose to apply this approach to determine the TRM.

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☒ Yes

☒ No

Comments: If a 0 MW TRM is reserved, it suggests that the TP and TOP are comfortable with the available control actions other than utilizing the transmission service reserved for TRM to address transmission uncertainties. On the other hand, the value of TRM reserved, including 0 MW, are subject to verification if need be. The question then becomes why 0 MW needs to be explained but not any other values? For example, other transmission users may question a high value of TRM reserved which reduces the ATC for use by others.

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☒ No

Comments: None, but there appears to be two requirements that pertain to access to external generation that may be duplicated or in excess of the CBM value: they are aggregate load forecast error and reserve sharing requirements. We suggest the SDT to review the two lists to eliminate any duplication or excessive allocation.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: None, but it should be noted that some entities do not provide physical transmission services and therefore some of the requirements in this standard may not be applicable to them.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments:

Requirement 1.1 should not only include generation dispatch variations but also peak and off peak dispatch variations. Additionally, Requirement 1.1 – the first line "Identification any of the following…" should be written to read as "Identification of any of the following…"

We have provided similar comments on the supplementary SAR, MOD-001 and MOD-004. The SAR for revising and creating this set of standards has not gone through prior public review and comment on the need and direction for these standards. It is posted simultaneously with the revised standard, making posting of the SAR irrelevant. Yet the revised standards appear to be uncoordinated, duplicated and convoluted in some.

We understand these standards need to be revised to meet the FERC's timeline but they should be done in a proper and orderly manner to ensure manageability not just by the staff and the SDT but also by the stakeholders in the industry. We do not agree with the process, and we do have trouble reviewing the set of standards that in our view are not well structured (for example: combining all 4 standards MOD-004 to MOD-007 into one). There has been no industry input process that either supports or disagrees with this proposed combining before the standards are drafted and posted.

And some of the standards assign responsibilities to entities that should not be responsible for some of the tasks. For example, the RC and PC are not responsible for calculating ATC. The proposed intent to combine some of the MODs as one includes the RC and PC in these standards because of the TTC calculation requirements. But in doing so, the assignment of tasks and responsibilities becomes confusing resulting in these entities being assigned some tasks inappropriately.

We suggest the SDT to revise the supplementary SAR and post it for comments, with sufficient detail and specificity on the proposed scope and structure of the standard set, before drafting/revising the standards.

Please use this form to submit comments on the 1st draft of standard MOD-008-1 Transmission Reliability Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

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| | ☐ | 3 — Load-serving Entities |
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| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** IRC Standards Review Committee

**Lead Contact:** **Charles Yeung**

**Contact Organization:** **SPP**

**Contact Segment:** **2**

**Contact Telephone:** **823-724-6142**

**Contact E-mail:** **cyeung@spp.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Jim Castle | NYISO | **NPCC** | 2 |
| Alicia Daugherty | PJM | **RFC** | 2 |
| Ron Falsetti | IESO | **NPCC** | 2 |
| Matt Goldberg | ISO-NE | **NPCC** | 2 |
| Brent Kingsford | CAISO | **WECC** | 2 |
| Steve Myers | ERCOT | **ERCOT** | 2 |
| Anita Lee | AESO | **WECC** | 2 |
| Bill Phillips | MISO | **RFC+** | 2 |
| | | **MOR+** | |
| | | **SERC+** | |
| | | **SPP** | |
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## Background Information

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Transmission Reliability Margin (TRM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-008-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations. Please review the 'White Paper' and the proposed MOD-008 before answering the questions on the following pages.  Comments must be submitted by **June 24, 2007**.  You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: We agree with combining the two standards, but the newly created standards contain quite a few more requirements than MOD-008-0 and MOD-009-0 taken together, and some of the requirements are duplicated (for example, R1 and R2). Also, some requirements are not clear as to who should be responsible, for example: there are conflicting yet sometimes duplicated requirements for documenting and calculating TRM. R1 and R2 hold the TP and TOP responsible for these task, yet R8 and R9 hold TSP responsible as well.

   There needs more clarity particularly in the accountability for documenting the methodology and in providing the supporting basis for determining TRM.

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: Most of the directives appear to be addressed. However, in view of the above comments, we expect the standards need more work so a revisit of this question is required.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: We do not think the standard clearly conveys the accountability of each of the responsibility entities well enough. Please see our comments to Q1 above.

   In addition, we feel that the entire set of MOD-001, -004, -008, -028, -029 and -30 lacks clarity in responsibility. For example, the RC and PC should not be responsible for calculating ATC. Why would they be included in the applicability section of some standards/requirements?

**4.** The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

☐ Yes

☒ No

Comments: There are a number of duplicated requirements (e.g. R1 and R2 as noted above_) and there is no clarity on the accountability (e.g. R9). The standard needs to be reviewed and revised to more clearly convey the roles and responsibilities in accordance with the functional model and today's practice (on a functional entity basis).

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments: We do not believe any maximum values should be set as a standard. Individual TSP (or TP and TOP according to the proposed standard) should each determine the amount needed to cover transmission uncertainties, which may vary among systems. The validity of the calculated values can be assessed against the documented methodology and audit process.

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☒ No

Comments: We do not believe this approach duly addresses the various components of TRM which may change depending on the system conditions. However, we hold no position on individual entities who choose to apply this approach to determine the TRM.

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☒ Yes

☒ No

Comments: If a 0 MW TRM is reserved, it suggests that the TP and TOP are comfortable with the available control actions other than utilizing the transmission service reserved for TRM to address transmission uncertainties. On the other hand, the value of TRM reserved, including 0 MW, are subject to verification if need be. The question then becomes why 0 MW needs to be explained but not any other values? For example, other transmission users may question a high value of TRM reserved which reduces the ATC for use by others.

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☒ No

Comments: None, but there appears to be two requirements that pertain to access to external generation that may be duplicated or in excess of the CBM value: they are aggregate load forecast error and reserve sharing requirements. We suggest the SDT to review the two lists to eliminate any duplication or excessive allocation.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: None, but it should be noted that some entities do not provide physical transmission services and therefore some of the requirements in this standard may not be applicable to them.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments: We have provided similar comments on the supplementary SAR, MOD-001 and MOD-004. The SAR for revising and creating this set of standards has not gone through prior public review and comment on the need and direction for these standards. It is posted simultaneously with the revised standard, making posting of the SAR irrelevant. Yet the revised standards appear to be uncoordinaed, duplicated and convoluted in some.

We understand these standards need to be revised to meet the FERC's timeline but they should be done in a proper and orderly manner to ensure manageability not just by the staff and the SDT but also by the stakeholders in the industry. We do not agree with the process, and we do have trouble reviewing the set of standards that in our view are not well structured (for example: combining all 4 standards MOD-004 to MOD-007 into one). There has been no industry input process that either supports or disagrees with this proposed combining before the standards are drafted and posted.

And some of the standards assign responsibilities to entities that should not be responsbile for some of the tasks. For example, the RC and PC are not responsible for calculating ATC. The proposed intent to combine some of the MODs as one includes the RC and PC in these standards because of the TTC calculation requirements. But in doing so, the assignment of tasks and responsibilities becomes confusing resulting in these entities being assigned some tasks inappropriately.

We suggest the SDT to revise the supplementary SAR and post it for comments, with sufficient detail and specificity on the proposed scope and structure of the standard set, before drafting/revising the standards.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

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*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team’s decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If “No,” please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission’s (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC’s directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If “No,” please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: Some of the requirements, such as R1.2 and R4 need additional work.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☒ No

   Comments: For once, the Reliability Coordinator may be an appropriate entity in these standards. TRM is addressing uncertainty. A real-time operator will be more aware of actual system uncertainties than most people, including planners. "Loopflow" has proven to an elusive animal to keep track of. TRM for loopflow is an important parameter. The RC should have input here.

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If “No,” please explain why in the comment area.

   ☒ Yes

   ☒ No

   Comments: This is a difficult question to answer but easily "measured". TRM is dealing with uncertainty so you're guessing at whatever you do. However, the ultimate real-time system response is your "test result" to see if you picked an appropriate TRM. If no one is denied service and there are no TLRs or congestion, you're right. If there are no or few TSR denials, and congestion or TLRs are persistent, the TRM is probably too low. If TSR is being denied and there is no evidence of congestion or TLR (level 3 for non-firm), TRM might be too high.

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a “maximum uncertainty” to support the validity of a TRM value? If “Yes,” please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☒ Yes

☒ No

Comments: You only need to investigate TRM if there is evidence of overselling or underselling. The compliance monitor should be so instructed. TRM is dealing with uncertainty. How do you study uncertainty? You don't, you just observe it in real-time.

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If “Yes,” please provide what you believe is an appropriate percentage in your response in the comments area.

☒ Yes

☐ No

Comments: 5% is appropriate. However, as we have stated before, it could change with observed system response. If you are using 5% and denying service with no TLRs or congestion, you may want to lower it. Compliance monitoring of this standard should (must) include this type of evaluation. Just picking a number only works if the real-time system response justifies it.

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: The justification is simple, no TLRs are observed and no market congestion is observed. If either symtom is present, TRM of zero is not justifiable. I.e, R1.5 is very easy to comply with.

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If “Yes,” please explain your answer in the comments area.

☒ Yes

☒ No

Comments: We're dealing with uncertainty here. What is legitimate uncertainty? There are enough requirements to find something to use.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments: As we have stated before, all compliance and measures should be based on evidence of overselling or underselling. Otherwise its just bureaucratic red-tape.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☒ Yes

   ☐ No

   Comments:

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a “maximum uncertainty” to support the validity of a TRM value? If “Yes,” please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments: Once the determination of TRM methodology has been identified, the TSP or TP or TC should use it to determine the required TRM values. It should not be required to perform many other studies to determine a TRM with the "maximum uncerttainty".

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If “Yes,” please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☒ No

Comments:

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If “Yes,” please explain your answer in the comments area.

☐ Yes

☒ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

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Comments:

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Comments:

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
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| **NERC Region** | | **Registered Ballot Body Segment** |
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The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations. Please review the 'White Paper' and the proposed MOD-008 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☒ No

   Comments: The Planning Coordinator and the Reliability Coordinator should have some role in this standard. They are listed as applicable Functional Entities that the standard is applicable yet they are not listed as the subject of any requirement.

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☒ Yes

   ☒ No

   Comments: 1. R1.2 should be revised to indicated that "A statement to confirm that it shall be used CONSISTENT assumptions in calculating TRM.." Same assumptions implies an exactness which is not appropriate and is not required by FERC Order 890. 2. Makes revisions to R1.1 and R2 per comments provided in response to Question 8 below.

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a “maximum uncertainty” to support the validity of a TRM value? If “Yes,” please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments: These studies should be coordinated as a NERC-wide activity outside of these standards.

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If “Yes,” please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☒ No

Comments: No - some of the area Transmission Service Providers use a percentage and also provide for incremental power flows for reserve sharing.

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: Generally zero TRM is potentially providing inadequate protection for reliability.

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If “Yes,” please explain your answer in the comments area.

☒ Yes

☐ No

Comments: Maintinance Outages, Uncertainty in Location of future generation, and uncertainty in power transactions. Also, the Standards Drafting Team should clarify that the Reserve sharing requirements are "Incremental power flows for reserve sharing requirements or automatic sharing of reserves."

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments: 1. The purpose of each of the standards should be revised to be more in-line. The purpose in this standard be revised by replacing "to help ensure more accurage calculation of transfer capabilities" with "for reliability system operations." 2. The Standards Drafting Team has defined a scheduling horizon in addition to an operating horizon and a planning horizon. Why did the Standards Drafting Team establish it and why have they defined it as provided in the standard.

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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**Lead Contact:**

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   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: This appears to require no consistency and appears to be a fill-in-the-blank standard.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: The Planning Coordinator and the Reliability Coordinator should have some role in this standard. They are listed as applicable Functional Entities that the standard is applicable yet they are not listed as the subject of any requirement.

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☐ Yes

   ☒ No

   Comments: Again, this still seems like a fill-in-the-blank standard.

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments:

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☐ No

Comments:

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: The reason for TRM is uncertainty. It is hard to believe that all of the ATC calculations are without uncertainty, so if uncertainty is buried in another part of the ATC calculation, it would be helpful to know where.

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☒ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: This appears to be a fill-in-the-blank standard.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments:

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☒ Yes

   ☐ No

   Comments:

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments: I don't know what the value of a maximum uncertainty would be. Each uncertainty has a probabalitic component to it. It would be simple enough to add up all the uncertainites but if the probalistic analysis determined that the maximum uncertainty event was once every 10 years or once every 15 years, I do not know what value that would have. If the standard listed some assumptions, e.g. events that you expect to see within a 1 year or 3 year time frame, then this analysis could become more meaningful.

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☐ No

Comments: I think that a percentage could be appropriate, but the best TRM value will always be one that is based on analysis of the potential uncertainties on a flowgate. I would hope that the committee will consider using a percentage as a default methodology, but allow for an analysis of uncertainties to modify the final value. A percentage would have to be based on flowgate capability. 5% may be a good default on a 100MW flowgate but overkil on a 1600MW flowgate.

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: The analysis need not be extensive and based on past performance, however a 0 TRM allows the tranmission custmers access to a flowgate with no margin of error, and some thought should be put into that situation.

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☒ Yes

☐ No

Comments: I believe that the need to hold back TRM for Inertial response is broad enough. Just as system load can degrade inertial response, system loading can degrade voltage response. I would recommend that initertial response be changed to include transient, dynamic, and voltage response.

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

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Comments:

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Robert W. Creighton | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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   ☒ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☐ No

   Comments:

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☐ Yes

   ☐ No

   Comments:

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☐ Yes

☒ No

Comments:

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☐ Yes

☒ No

Comments:

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: explaination may divulge commercially sensitive or critical infrastructure information

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☐ No

Comments: in the case of a system that is radially connected to other systems via a single interconnection will become islanded for a single contingency (loss of the interconnection). If the system was importing more than 10% (nominal) of its load at the time of the interconnection, the system will likely trigger Stage 1 under frequency load shedding. Therefore there must be a TRM facto that varies with system load to limit the amount of UFLS. In Nova Scotia, we set the import limit at 22% of total net load on our system to avoid Stage 2 UFLS for a single contingency. We use TRM as that variable (with additional margin for load forecast uncertainty. It is not clear if this need is addressed in this standard. Another need would be to share load following with our neighbour (AGC margin). For example, if NS and NB are jointly controlling the NB-New England tie, the NS-NB tie capacity must be held back from its TTC to allow room to respond to load and generation fluctuations (especially wind generation). The latter may be the intent of the R2 "Variations in generation dispatch".

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☒ No

Comments: Tariffs and Market Rules may have to be updated to reflect the new requirements of MOD-008.

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments:

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<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☐ NPCC<br>☐ RFC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
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<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

**Group Name:** Public Service Commission of South Carolina

**Lead Contact:** **Phil Riley**

**Contact Organization:** **Public Service Commission of South Carolina**

**Contact Segment:** **9**

**Contact Telephone:** **803-896-5154**

**Contact E-mail:** **philip.riley@psc.sc.gov**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mignon L. Clyburn | PSCSC | **SERC** | 9 |
| G. O'Neal Hamilton | PSCSC | **SERC** | 9 |
| John E. "Butch" Howard | PSCSC | **SERC** | 9 |
| Randy Mitchell | PSCSC | **SERC** | 9 |
| C. Robert "Bob" Moseley | PSCSC | **SERC** | 9 |
| David A. Wright | PSCSC | **SERC** | 9 |
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**1.** The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

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Comments:

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☐ No

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**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☐ No

Comments: Our comments are from a regulatory perspective. This is strictly a technical issue.

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☐ No

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**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

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☐ Yes

☒ No

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | Southern Company |
| **Lead Contact:** | **DuShaune Carter** |
| **Contact Organization:** | **Southern Company Services** |
| **Contact Segment:** | |
| **Contact Telephone:** | **205-257-5775** |
| **Contact E-mail:** | **ddcarter@southernco.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| JT Wood | Southern Company Services | **SERC** | 1 |
| Roman Carter | Southern Company Services | **SERC** | 1 |
| Gary Gorham | Southern Company Services | **SERC** | 1 |
| Marc Butts | Southern Company Services | **SERC** | 1 |
| Bill Botters | Southern Company Services | **SERC** | 1 |
| Ron Carlsen | Southern Company Services | **SERC** | 1 |
| Jim Howell | Southern Company Services | **SERC** | 1 |
| Jeremy Bennett | Southern Company Services | **SERC** | 1 |
| Jim Viikinsalo | Southern Company Services | **SERC** | 1 |
| Reed Edwards | Southern Company Services | **SERC** | 5 |
| Dean Ulch | Southern Company Services | **SERC** | 1 |
| Garey Rozier | Southern Company Services | **SERC** | 5 |
| Karl Moor | Southern Company Services | **SERC** | 1 |
| Chuck Chakravarthi | Southern Company Services | **SERC** | 1 |
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   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

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   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments:

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☒ No

Comments:

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: It is unclear what benefit would be gained by requiring the Transmission Planner or Transmission Operator to supply this explanation.

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☒ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

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|---|---|---|
| Name: | | |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** SERC Available Transfer Capability Working Group (ATCWG)

**Lead Contact:** **John Troha**

**Contact Organization:** **SERC Reliability Corporation**

**Contact Segment:** **10 - RRO**

**Contact Telephone:** **704-948-0761**

**Contact E-mail:** **jtroha@serc1.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Darrell Pace | Alabama Electric Cooperative, Inc | **SERC** | 10 |
| Helen Stines | Alcoa Power Generating, Inc. | | |
| Eugene Warnecke | Ameren | | |
| Don Reichenbach | Duke | | |
| Joachim Francois | Entergy | | |
| Ross Kovacs | Georgia Transmission Corporation | | |
| Larry Middleton | Midwest ISO | | |
| Jerry Tang | Municipal Electric Authority of Georgia | | |
| John Troha | SERC Reliability Corporation | | |
| Al McMeekin | South Carolina Electric and Gas Company | | |
| Stan Shealy | South Carolina Electrica nd Gas Company | | |
| Carter Edge | SERC Reliability Corporation | | |
| DuShaune Carter | Southern Company Services, Inc. -Trans | | |
| Bryan Hill | Southern Company Services, Inc. -Trans | | |
| Doug Bailey | Tennessee Valley Authority | | |
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   ☒ Yes

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   ☐ No

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**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a “maximum uncertainty” to support the validity of a TRM value? If “Yes,” please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments: Once the determination of TRM methodology has been identified, the TSP or TP or TC should use it to determine the required TRM values. It should not be required to perform many other studies to determine a TRM with the "maximum uncertainty".

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If “Yes,” please provide what you believe is an appropriate percentage in your response in the comments area.

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☐ No

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | W. Shannon Black Et Al ; Sacramento Municipal Utility District | |
| Organization: | Sacramento Municipal Utility District | |
| Telephone: | (916) 732-5734 | |
| E-mail: | sblack@smud.org | |

| **NERC Region** | | **Registered Ballot Body Segment** |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** WECC MIC MIS ATC TF

**Lead Contact:** **W. Shannon Black**

**Contact Organization:** **Sacramento Municipal Utility District**

**Contact Segment:** **Various**

**Contact Telephone:** **(916) 732-5734**

**Contact E-mail:** **sblack@smud.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| The 24 individuals listed in this same section for MOD-01 comments, filed jointly with this filing, by the WECC MIC MIS ATC TF Team, have either actively monitored this work product or have actively engaged in drafting the attached comments. That Team list of 24 individuals applies to jointly to MOD-01; MOD-04; MOD-08; MOD-29 and MOD-30. | | | |
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   ☐ Yes

   ☐ No

   Comments: No comment.

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   ☐ Yes

   ☒ No

   Comments:

   First, the "Applicability" section uses the term "Planning Coordinator" which is not a defined term in the NERC Glossary. If the NERC Team intends it use, it should become a defined term.

   Second, where the term Planning Coordinator is used, WECC queries whether or not the more accurate entity would be the Transmission Planner.

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☐ Yes

   ☐ No

   Comments:

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☒ No

Comments:

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☒ Yes

☐ No

Comments:

Two to five percent is acceptable. However, it should not be mandated as the single methodology allowed. Further, the TRM has multiple components, one of which is the Reserve Sharing Group component. The 2-5% is not appropriately applied to the Reserve Sharing Group subset of TRM; rather, the 2-5% accurately applies only to the "uncertainty" portion of the TRM.

While this methodology may be sufficient for several TSPs, it may not be sufficient for others. Therefore, use of this type of percentage should not be the only mechanism available for TSPs to determine TRM on their systems.

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☒ No

Comments: Howver, the NERC Team should clarify that the uncertainties listed in R1.1 "may" be used in TRM calculations (as opposed to being required to be used).

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments:

A.

Reiterating comments from MOD-04 CBM, the Team suggests the following CBM definition replace the existing CBM and TRM NERC defintions:

“Capacity Benefit Margin”

CBM is the amount of firm import transmission capability, requested by the LSE, to exclusively serve identified load only during periods of emergency generation deficiencies extending beyond the beginning of the scheduling hour in which the emergency generation deficiency occurs.”

B.

Typo on the first line of R1.1. Should state: "Identification of any of the following…"

C.

R8. Add: "Each Transmisison Service Provider shall make available (within seven CALENDAR days OF A REQUEST)… (Emphasis added.)

D.

As previously stated, there is an existing FERC approved definition for Posted Path that should be included in the NERC Glossary and utilized in the ATC standards.

R10. The term Posted Path should be used as a defined term.

The definition for Posted Path should be as follows:

Posted Path

Posted Path means: 1) any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.

E.

R5. Should read "…(on each POSTED PATH or Flowgate)…"

F.

R2. At minimum, the word "Contract Path" should be deleted as the intent is to cover all Posted Paths. This Team continues to suggest the adoption of the CFR defined term "Posted Path" that is the more accurate useage for this R.

G.

R11. Should be reworded as neither the Transmission Planner nor the Transmission Operator "reserve capacity" on their system(s). That's not within their Functional Model purview. The Transmission Planner and the Transmission Operator can identify capacity that "should be reserved" on their system(s); however, the Transmission Service Provider is the accurate entity to actually "reserve" the capacity.

Please use this form to submit comments on the 1st draft of standard MOD-008-1 Transmission Reliability Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Chuck Falls | |
| Organization: | Salt River Project | |
| Telephone: | 602 236-0965 | |
| E-mail: | Chuck.Falls@srpnet.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculations and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Transmission Reliability Margin (TRM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-008-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations. Please review the 'White Paper' and the proposed MOD-008 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☐ No

   Comments:

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

   ☐ Yes

   ☐ No

   Comments:

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☐ No

Comments:

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☐ No

Comments:

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: This is unnecessary "busy work." FERC is concerned about TSP's hoarding transmission capacity by unjustifiably setting aside large quantities of TRM. If I set aside zero TRM this should make FERC very happy because it frees up more ATC for purchase. By making me justify why I am setting aside zero TRM I am being encouraging to set aside non-zero TRM to avoid having to justify it. At the very least R1.5 should be rewritten to clarify precisely what circumstance require justification for zero TRM. For example, if I set aside zero TRM for only one hour on only one path do I have to explain why? Conversely, if I have zero TRM for all time periods and for all paths but one have I avoided the need to justfy why I have zero TRM for the other paths?

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

## Consideration of Comments on 2nd Draft of Standard MOD-008-1 — Available Transfer Capability (Project 2006-07)

The ATC Standard Drafting Team requesters thank all commenters who submitted comments on First Draft of Standard MOD-008-1 TRM. This SAR was posted for a 30-day public comment period from May 25 through June 24, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 19 sets of comments, including comments from 95 different people from more than 45 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received from stakeholders, comments from the cooperative effort with NAESB in developing associated business practices, and comments received from FERC staff, the drafting team has significantly redrafted the standard. The changes have been so extensive that the revised standard bears very little resemblance to the last posted draft. Major changes include:

- Added a new term, 'Transmission Reliability Margin Implementation Document' that replaces the references to a Transmission Reliability Margin Calculation Methodology
- Expanded the purpose statement
- Eliminated the Transmission Planner, Reliability Coordinator, Planning Coordinator and Load-serving Entity from the applicability section of the standard
- Revised R1 to limit applicability to the Transmission Operator
- Absorbed R2 into R1 and expanded R1 to add more specificity to the documentation the Transmission Operator must have to support its TRM calculation methodology, including new language that:
    - Clarifies that documentation must be provided for each Posted Path or Flowgate
    - Requires that the documentation of the uncertainties used in calculating TRM include maintenance outages and future generation
    - Requires that the documentation of the uncertainties used in calculating TRM include uncertainties regarding frequency bias
    - Requires documentation of the practice if TRM is zero for all time periods rather than requiring why it did not reserve any TRM
    - Added an upper boundary of up to 13 months for the calculation of TRM in the 'beyond day-ahead and pre-schedule' time period
    - Eliminated references (from original R2) to posted Contract Paths
- Modified what had been R3 and R4 (now R2 in the revised standard) to clarify that the uncertainties used in calculating TRM may not include any of the components of CBM
- Modified R5 and merged it with R6, moving the requirement for the Transmission Planner to calculate TRM for the time period beyond the day-ahead and pre-schedule period to the Transmission Operator - and added an outer boundary of 13 months to the 'beyond the day-ahead and pre-schedule' time period.
- Eliminated R7 which required the Transmission Service Provider to make its TRM calculation methodology publicly available – the posting requirements will be addressed in NAESB business practices.
- Modified R8 so that the Transmission Service Provider is only required to provide its TRM Implementation Document and associated documentation to those Transmission

Service Providers who have made a request for the information – the requirement to provide the information to transmission customers and load-serving entities has been removed

- Modified R9 (now R3) to limit applicability to the Transmission Operator and added some words to improve the clarity
- Eliminated R10 as the posting requirements are being addressed by NAESB
- Eliminated R11 which required the Transmission Planner and Transmission Operator that reserved capacity on its transmission system for use as TRM to also use TRM in its ATC or AFC calculations.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Jason Murray (G6) | AESO | | ✓ | | | | | | | | |
| 2. | Darrell Pace (G3) | Alabama Electric Coop., Inc. | | | | ✓ | ✓ | ✓ | | | | |
| 3. | Anita Lee (G1) | Alberta Electric System Operator | | ✓ | | | | | | | | |
| 4. | Helen Stines (G3) | Alcoa Power Generating, Inc. | | | | | | ✓ | ✓ | ✓ | ✓ | |
| 5. | Eugene Warnecke (G3) | Ameren | ✓ | | ✓ | | | ✓ | | | | |
| 6. | E. Nick Henery | APPA | ✓ | | | | | | | | | |
| 7. | Jerry Smith (G6) | APS-TP | | | | | | | | | | |
| 8. | Steve Tran (G6) | BP TX | | | | | | | | | | |
| 9. | Abbey Nulph (G6) (I) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 10. | Rebecca Berdahl (G6) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 11. | Steve Knudsen (G6) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 12. | Charles Mee (G6) | CA Dept Water & Power | | | | | | | | | | |
| 13. | Brent Kingsford (G1) | California ISO | | ✓ | | | | | | | | |
| 14. | Greg Ford (G6) | CISO-TP | | ✓ | | | | | | | | |
| 15. | Greg Rowland | Duke Energy | ✓ | | ✓ | | | | | | | |
| 16. | Don Reichenbach (G3) | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 17. | Narinder K. Saini | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 18. | George Bartlett | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 19. | Jim Case | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 20. | Ed Davis | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 21. | Joachim Francois (G3) | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 22. | Steve Myers (I) (G1) | ERCOT | | ✓ | | | | | | | | |
| 23. | Patricia vanMidde (G6) | FERC Case MRG, Sempra | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24. | Dave Folk | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 25. | Richard Kovacs | FirstEnergy Corp. EDPP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 26. | Phil Bowers | FirstEnergy Corp. EDPP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 27. | Ross Kovacs (G3) | Georgia Transmission Corp. | ✓ | | ✓ | | | | | | | |
| 28. | Roger Champagne | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 29. | Danielle Beaulieu | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 30. | Daniel Soulier | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 31. | Ron Falsetti (I) (G1) | Independent Electricity System Operator (IESO) | | ✓ | | | | | | | | |
| 32. | Lou Ann Westerfield (G6) | IPUC-SP | | | | | | | | | | |
| 33. | Matthew F. Goldberg (I) (G1) | ISO New England (ISO-NE) | | ✓ | | | | | | | | |
| 34. | Brian Thumm | ITC Transco | ✓ | | | | | | | | | |
| 35. | Sueyen McMahon (G6) | LADWP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 36. | Eric Ruskamp (G2) | LES | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 37. | Michelle Rheault | Manitoba Hydro | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 38. | Jerry Tank (G3) | MEAG | ✓ | | ✓ | | ✓ | | | | | |
| 39. | Dennis Kimm | MidAmerican Energy – Energy/Trading (MEC Trading) | | | ✓ | | ✓ | ✓ | | | | |
| 40. | Tom Mielnik (I) (G2) | MidAmerican Energy Co. (MEC) | | | ✓ | | ✓ | ✓ | | | | |
| 41. | Bill Phillips (G1) | Midwest ISO | | ✓ | | | | | | | | |
| 42. | Larry Middleton (G3) | Midwest ISO | | ✓ | | | | | | | | |
| 43. | Carol Gerou (G2) | Minnesota Power | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 44. | Terry Bilke (G2) | MISO | | ✓ | | | | | | | | |
| 45. | Mike Brytowski (G2) | MRO | | | | | | | | | | ✓ |
| 46. | Matt Schull | NCMPA (with APPA) | | | | | ✓ | | | | | |
| 47. | Jim Castle (G1) | New York ISO | | ✓ | | | | | | | | |
| 48. | Robert W. Creighton | Nova Scotia Power, Inc. (NPSI) | ✓ | | | | | | | | | |
| 49. | Todd Gosnell (G2) | OPPD | ✓ | | ✓ | | | ✓ | | | | |
| 50. | Brian Weber (G6) | Pacificorp | ✓ | | | | ✓ | | | | | |
| 51. | Alicia Daugherty (G1) | PJM | | ✓ | | | | | | | | |
| 52. | Mignon L. Clyburn (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 53. | G. O'Neal Hamilton (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 54. | John E. Howard (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 55. | Randy Mitchell (G5 | PSC of South Carolina | | | | | | | | | ✓ | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 56. | C. Robert Moseley (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 57. | David A. Wright (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 58. | Philip Riley (G5) | PSC of South Carolina (PSC SC) | | | | | | | | | ✓ | |
| 59. | Chuck Falls (I) (G6) | Salt River Project (SRP) | ✓ | | | | | | | | | |
| 60. | John Troha (G3) | SERC | | | | | | | | | | ✓ |
| 61. | Carter Edge (G3) | SERC | | | | | | | | | | ✓ |
| 62. | Bob Schwermann (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 63. | Brian Jobson (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 64. | Dick Buckingham (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 65. | Dilip Mahendra (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 66. | W. Shannon Black (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 67. | Phil Odonnell (G6) | SMUD- Ops | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 68. | Al McMeekin (G3) | South Carolina Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |
| 69. | Stan Shealy (G3) | South Carolina Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |
| 70. | JT Wood (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 71. | Roman Carter (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 72. | Gary Gorham (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 73. | Marc Butts (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 74. | Bill Botters (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 75. | Ron Carlsen (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 76. | Jim Howell (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 77. | Jeremy Bennett (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 78. | Jim Viikinsalo (G4 | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 79. | Reed Edwards (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 80. | Dean Ulch (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 81. | Garey Rozier (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 82. | Karl Moor (G4) | Southern Company Services, | ✓ | | | | ✓ | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Inc. | | | | | | | | | | |
| 83. | Chuck Chakravarthi (G4) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 84. | DuShaune Carter (G4) | Southern Transmission | ✓ | | | | | | | | | |
| 85. | Charles Yeung (G1) | Southwest Power Pool | | ✓ | | | | | | | | |
| 86. | Casey Sprouse (G6) | Sr. Term Marketer | | | | | | | | | | |
| 87. | Maria Denton (G6) | SRP | | | | | | | | | | |
| 88. | Terri M. Kuehneman (G6) | SRP System Operation | | | | | | | | | | |
| 89. | Raquel Agular (G6) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 90. | Ron Belval (G6) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 91. | Jim Haigh (G2) | WAPA | | | | | | | | | ✓ | |
| 92. | Raymond Vojdani (G6) | WAPA | | | | | | | | | ✓ | |
| 93. | Mike Wells (G6) | WECC | | | | | | | | | | ✓ |
| 94. | Neal Balu (G2) | WPS | | | ✓ | | ✓ | ✓ | | | | |
| 95. | Pam Oreschnick (G2) | XEL | ✓ | | ✓ | | ✓ | ✓ | | | | |

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – IRC Standards Review Committee (IRC)
G2 – MRO Members (MRO)
G3 – SERC Available Transfer Capability Working Group (SERC ATCWG)
G4 – Southern Company Services, Inc. (SOCO)
G5 – Public Service Commission of South Carolina (PSC SC)
G6 - WECC MIC MIS ATC Task Force

## Index to Questions, Comments, and Responses

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If "No," please explain why in the comments area.

**Summary Consideration:** The majority of commenters agreed with the combination. The Standard Drafting Team has redrafted the standard to eliminate the duplication between R1 and R2, as well as clear up some of the confusion and conflicts in regard to responsibilities. Please see the list of major changes made to the standard on the cover page of this report.

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| IESO<br>IRC SRC | ☑ | ☑ | We agree with combining the two standards, but the newly created standards contain quite a few more requirements than MOD-008-0 and MOD-009-0 taken together, and some of the requirements are duplicated (for example, R1 and R2). Also, some requirements are not clear as to who should be responsible, for example: there are conflicting yet sometimes duplicated requirements for documenting and calculating TRM. R1 and R2 hold the TP and TOP responsible for these tasks, yet R8 and R9 hold TSP responsible as well.<br><br>There needs more clarity particularly in the accountability for documenting the methodology and in providing the supporting basis for determining TRM. |
| **Response:** The Standard Drafting Team has redrafted the standard to eliminate the duplication between R1 and R2, as well as clear up some of the confusion and conflicts in regard to responsibilities. Please see the list of major changes made to the standard on the cover page of this report. | | | |
| APPA | ☑ | | |
| Duke Energy | ☑ | | |
| ERCOT | ☑ | | |
| FirstEnergy | ☑ | | |
| ITC | ☑ | | |
| MEAG | ☑ | | |
| MEC | ☑ | | |
| MEC Trading | ☑ | | |
| Manitoba Hydro | ☑ | | |
| MRO | ☑ | | |
| NPSI | ☑ | | |

| Question #1 | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| PSC SC | ☑ | | |
| SERC ATCWG | ☑ | | |
| WECC MIC MIS ATC TF | ☑ | | |
| SOCO | ☑ | | |

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If "No," please explain why in the comments area.

**Summary Consideration:** While most stakeholders who responded to this question indicated that the SDT has adequately responded to the directives in Order 890 and 693, there were some suggestions for improvement. The SDT has redrafted some parts of the standard to address these stakeholder suggestions.
R1.2 was modified as follows:

**R1.2** A statement to confirm that it shall use ~~the same~~ consistent assumptions in calculating TRM as those that are used in the transmission planning process for the appropriate time periods.

R3 and R4 were modified as follows:

**R~~3~~2.** The ~~Transmission Planner and~~ Transmission Operator shall only use the components of uncertainty from R1.1 to calculate TRM , and not include any of the components of CBM.

~~R4. The Load-Serving Entity shall not use the components of uncertainty from R1.1 to determine its CBM megawatt import requirement.~~

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The SDT has addressed most of the issues in the FERC Orders. However, it is not clear from the Standard that once transmission capacity has been reserved as TRM, under what circumstances can energy be scheduled on TRM transmission Capacity? |
| **Response:** The standard drafting team does not believe it is appropriate to specify scheduling requirements in this standard. | | | |
| Duke Energy | | ☑ | It is unclear that the drafting team has addressed FERC's direction in paragraph 275 of Order No. 890 to establish appropriate maximum TRM. Perhaps the Standards Drafting Team should consider using the TPL standards requirements as a basis for bounding the maximum TRM value. |
| **Response:** The drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the types of uncertainty listed in the standard. | | | |
| ITC | | ☑ | Some of the requirements, such as R1.2 and R4 need additional work. |
| **Response:** The drafting team has redrafted the standard to address these comments.<br>Please see the list of modifications made to the standard listed on the cover page of this report. Both R1.2 and R4 were modified. | | | |
| MEC Trading | | ☑ | This appears to require no consistency and appears to be a fill-in-the-blank standard. |
| **Response:** The standard drafting team feels that because different entities experience different amounts of uncertainty, | | | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| flexibility is required in this standard.. For example, some entities experience much larger loop flows through their system than other entities. | | | |
| IESO<br>IRC SRC | ☑ | ☑ | Most of the directives appear to be addressed. However, in view of the above comments, we expect the standards need more work so a revisit of this question is required. |
| **Response:** The Standard Drafting Team has continued to diligently work on the standard and has made numerous change based on comments from stakeholders, NAESB and FERC. Please see the list of modifications made to the standard listed on the cover page of this report. | | | |
| ERCOT | ☑ | | |
| FirstEnergy | ☑ | | |
| HQT | ☑ | | |
| MEC | ☑ | | |
| Manitoba Hydro | ☑ | | |
| MRO | ☑ | | |
| PSC SC | ☑ | | |
| WECC MIC MIS ATC TF | ☑ | | |
| SOCO | ☑ | | |

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why

**Summary Consideration:** There was no consensus amongst the stakeholders who responded to this question – however several commenters indicated here and elsewhere that the standard should not apply to the Reliability Coordinator or the Planning Coordinator, and the Standard Drafting Team has removed the Reliability Coordinator and Planning Coordinator from the applicability section of the standard.

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The Applicable Reliability Functions are identified; however the standard is requiring those Functions to duplicate their duties in this Standard that is required in other Standards. If this Standard wants to post the results of those duties, then the correct standard must be referenced in lieu of repeating the requirement. |
| **Response:** It is not the standard drafting team's intention to repeat requirements in other standards. The drafting team has examined the other reliability standards to check for repeat requirements and found no repeated requirements. | | | |
| BPA | | ☑ | "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority. |
| **Response:** Planning Coordinator is the current terminology used in the NERC Functional Model. We will add this definition to the Glossary. Note that the Standards Committee directed all drafting teams to begin using the term, 'Planning Coordinator' in the drafting of reliability standards. | | | |
| Duke Energy | | ☑ | This standard shouldn't be applicable to the Reliability Coordinator because this is a calculation methodology, and Reliability Coordination is a real-time role. Also, it is unclear which requirements of this standard apply to the Planning Coordinator. Unless specific roles in TRM determination are identified for the Reliability Coordinator and Planning Coordinator, they should be deleted from the Applicability section. |
| **Response:** The Standard Drafting Team has removed the Reliability Coordinator and Planning Coordinator from the applicability section of the standard | | | |
| ERCOT | | ☑ | There is no requirement applicable to Reliability Coordinator or Planning Coordinator. Therefore, MOD-008-1 should not be applicable to Reliability Coordinator and Planning Coordinator. |
| **Response:** The Standard Drafting Team has removed the Reliability Coordinator and Planning Coordinator from the applicability section of the standard. | | | |
| IESO<br>IRC SRC | | ☑ | We do not think the standard clearly conveys the accountability of each of the responsibility entities well enough. Please see our comments to Q1 above.<br><br>In addition, we feel that the entire set of MOD-001, -004, -008, -028, -029 and -30 lacks clarity in |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | responsibility. For example, the RC and PC should not be responsible for calculating ATC. Why would they be included in the applicability section of some standards/requirements? |
| **Response:** The standard drafting team has identified, for each requirement, the entity accountable for carrying out that requirement. Note that the applicability section of the standard was revised, and the standard no longer has any requirements applicable to the Planning Coordinator or the Reliability Coordinator. | | | |
| MEC<br>MEC Trading | | ☑ | The Planning Coordinator and the Reliability Coordinator should have some role in this standard. They are listed as applicable Functional Entities that the standard is applicable yet they are not listed as the subject of any requirement. |
| **Response:** The Standard Drafting Team has removed the Reliability Coordinator and Planning Coordinator from the applicability section of the standard. They are recipients of some of the products, but they are not assigned accountability for any requirements. | | | |
| MRO | | ☑ | The MRO believes that the Planning Coordinator and the Reliability Coordinator should have some role in this standard. They are listed as applicable Functional Entities that the standard is applicable yet they are not listed as the subject of any requirement. |
| **Response:** The Standard Drafting Team has removed the Reliability Coordinator and Planning Coordinator from the applicability section of the standard. They are recipients of some of the products, but they are not assigned accountability for any requirements. | | | |
| ITC | ☑ | ☑ | For once, the Reliability Coordinator may be an appropriate entity in these standards. TRM is addressing uncertainty. A real-time operator will be more aware of actual system uncertainties than most people, including planners. "Loopflow" has proven to an elusive animal to keep track of. TRM for loopflow is an important parameter. The RC should have input here. |
| **Response:** The SDT agrees that a real-time operator will have first hand knowledge of actual system uncertainties, which is why the Transmission Operator was included in the applicability of the standard. The SDT reviewed the standard and the functional model and did not assign any requirements to the Reliability Coordinator. | | | |
| FirstEnergy | ☑ | | |
| MEAG | ☑ | | |
| Manitoba Hydro | ☑ | | |
| PSC SC | ☑ | | |
| WECC MIC MIS ATC TF | ☑ | | No comment. |
| SOCO | ☑ | | |

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If "No," please explain why in the comment area.

**Summary Consideration:** Several stakeholders suggested modifying or deleting some of the requirements in the first draft of the standard. Based on stakeholder comments, the SDT has deleted R2, and the language in R1 was modified to address R2's deletion as shown below (text highlighted in yellow was in both R1 and R2 in the last draft of the standard – text highlighted in red was added based on stakeholder comments or to better meet the FERC directives):

**R1.1.** Identification ~~any~~ of (on each of its respective Posted Paths or Flowgates) each of the following components of uncertaint~~ies~~y if used to calculate ~~its~~ a TRM value:

- Aggregate Load forecast ~~error~~ uncertainty (not included in determining generation reliability requirements).
- Load distribution ~~error~~ uncertainty.
- Forecast uncertainty in transmission system topology (including maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions
- Variations in generation dispatch (including maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve sharing requirements.
- Inertial response and frequency bias.

Based on stakeholder comments, the SDT has rewritten R3 and eliminated R4 from the standard as shown below (now combined into R2 in the revised standard):

R~~3~~2. The ~~Transmission Planner and~~ Transmission Operator shall only use the components of uncertainty from R1.1 to calculate TRM , and not include any of the components of CBM.

~~R4. The Load-Serving Entity shall not use the components of uncertainty from R1.1 to determine its CBM megawatt import requirement.~~

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The standard is requiring Applicable Functions to duplicate their duties in this Standard that are required in other Standards. This Standard as written created duplication of same actions in two different and will cause confusion within the Compliance Program. R 1.1 and R 2 seem to say the |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | same thing. This Standard should not set or limit the ways a Planner will determine uncertainty in their in their calculations. It should require that all factors used to determine its uncertainty is provided, but do not set or limit the possibilities. This Standard's scope for TRM does not include the authority to determine study methods. |
| **Response:** It is not the standard drafting team's intention to repeat requirements in other standards. We have examined the other reliability standards to check for duplicate requirements, and found none. The Standard Drafting Team agrees there is some redundancy in Requirement R1 and Requirement R2, and revised the standard by merging R1 and R2 into a single requirement, eliminating the redundancy.<br><br>In order to obtain consistency between the different TRM calculation methodologies we have limited the types of uncertainty that can be used in a TRM calculation. The revised standard does not limit the study methods used in calculating the different types of uncertainty. | | | |
| BPA | | ☑ | R1.3. should read "The description of the method of allocation across Posted Paths or Flowgates" where Posted Path is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.<br>R2. -- The parenthetical statement should read "…on each of its respective Posted Paths or Flowgates..."<br>R5. and R6. -- The term "path" should be replaced with "Posted Path".<br>R10. -- The term "posted path" should be capitalized. |
| **Response:** The standard drafting team has implemented the suggested changes and they are reflected in the revised standard. | | | |
| Duke Energy | | ☑ | There is no requirement for coordination between the Transmission Operator and the Transmission Planner. Also, there should be a requirement that the TRM values should be equal to or lower than long-term TRM as you move closer to real-time and uncertainty diminishes. |
| **Response:** The standard drafting team revised the standard to require Transmission Operator calculate TRM and for the Transmission Operator to provide the TRM values to the Transmission Planner. The standard drafting team feels that these modifications address Duke Energy's concerns. | | | |
| ERCOT | | ☑ | It is not clear if the intent of R2 is to document component of uncertainty on TRM on each posted path, or a general process to include impact of uncertainties in TRM methodologies is sufficient. The requirement should clarify such that the impact of uncertainties are included in TRM methodologies and not to document each component.<br>R4 is written as a requirement for CBM methodology rather than for TRM methodology, it should be deleted or reworded. |
| **Response:** The SDT has deleted R2, and the language in R1 was modified to address R2's deletion. We have included this requirement such that the different assumptions used in determining TRM across your system can be understood. The intent is for the information to be posted for each posted path or flowgate, as stated in the requirement. | | | |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Upon examining R4, we have rewritten R3 and eliminated R4 from the standard. (See R2 in the revised standard.) | | | |
| HQT | | ☑ | Variations in facility loading should be back in the R1.1 list |
| **Response:** We have updated the language to replace "error" with "uncertainty," which we believe should address your concern. We also believe "Variation in Generation Dispatch" will address this. The drafting team believes that R1.1 contains the components that will cause variations in facility loadings, so adding this would be redundant. | | | |
| IESO<br>IRC SRC | | ☑ | There are a number of duplicated requirements (e.g. R1 and R2 as noted above_) and there is no clarity on the accountability (e.g. R9). The standard needs to be reviewed and revised to more clearly convey the roles and responsibilities in accordance with the functional model and today's practice (on a functional entity basis). |
| **Response:** There were some redundancies in Requirement R1 and Requirement R2, which have been addressed with new language. R2 was eliminated as a separate requirement, and was merged into R1.<br>R9 was modified (now R3) to limit applicability to the Transmission Operator and added some words to improve the clarity | | | |
| ITC | ☑ | ☑ | This is a difficult question to answer but easily "measured". TRM is dealing with uncertainty so you're guessing at whatever you do. However, the ultimate real-time system response is your "test result" to see if you picked an appropriate TRM. If no one is denied service and there are no TLRs or congestion, you're right. If there are no or few TSR denials, and congestion or TLRs are persistent, the TRM is probably too low. If TSR is being denied and there is no evidence of congestion or TLR (level 3 for non-firm), TRM might be too high. |
| **Response:** This could be an approach to validate the calculated TRM but it is something that may not belong in the TRM requirements (but perhaps in measures and compliance). | | | |
| MEC Trading | | ☑ | Again, this still seems like a fill-in-the-blank standard. |
| **Response:** Because different entities experience different amount of uncertainty, flexibility is required in this standard in order to account it in each area. For example, some entities experience much larger loop flows through their system than other entities. | | | |
| WECC MIC MIS ATC TF | | ☑ | First, the "Applicability" section uses the term "Planning Coordinator" which is not a defined term in the NERC Glossary. If the NERC Team intends it use, it should become a defined term.<br><br>Second, where the term Planning Coordinator is used, WECC queries whether or not the more accurate entity would be the Transmission Planner. |
| **Response:** Planning Coordinator is current terminology used in the NERC Functional Model and the drafting team is taking steps to add this to the NERC Glossary. However, the standard drafting team did revise the applicability section of the standard to address other industry comments suggesting that the standard should not be applicable to the Planning Coordinator, and the standard was revised so that there are no requirements applicable to the Planning Coordinator. | | | |
| MRO<br>MEC | ☑ | ☑ | 1. R1.2 should be revised to indicated that "A statement to confirm that it shall be used CONSISTENT assumptions in calculating TRM.." Same assumptions implies an exactness which is not appropriate and is not required by FERC Order 890. |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | 2. Makes revisions to R1.1 and R2 per MRO comments provided in response to Question 8 below. |
| **Response:** The standard drafting team modified the standard in support of your suggestion, and the revised standard R1.2 uses the phrase, 'consistent assumptions'.<br><br>Please see the response to your comments on Question 8. | | | |
| Manitoba Hydro | ☑ | | |
| FirstEnergy | ☑ | | |
| MEAG | ☑ | | |
| PSC SC | ☑ | | |
| SERC ATCWG | ☑ | | |
| SOCO | ☑ | | |

5. Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a "maximum uncertainty" to support the validity of a TRM value? If "Yes," please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

**Summary Consideration:** The majority of commenters did not believe that a study should be required. The drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the types of uncertainty listed in the standard.

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSC SC | | | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| APPA | | ☑ | This Standard should only require the TRM value be provided and the associated assumptions for determine the amount of error in the planning or operating studies. |
| **Response:** The standard drafting team feels that in order to obtain some consistency in TRM calculations we should define the types of uncertainty that can be used to determine TRM. | | | |
| BPA | | ☑ | Please clarify that the uncertainties listed in R1.1 may be used in TRM calculations (as opposed to being required to be used). |
| **Response:** The standard currently states that the information must be provided only "if used." | | | |
| IESO<br>IRC SRC | | ☑ | We do not believe any maximum values should be set as a standard. Individual TSP (or TP and TOP according to the proposed standard) should each determine the amount needed to cover transmission uncertainties, which may vary among systems. The validity of the calculated values can be assessed against the documented methodology and audit process. |
| **Response:** The drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the types of uncertainty listed in the standard. | | | |
| MEAG | | ☑ | Once the determination of TRM methodology has been identified, the TSP or TP or TC should use it to determine the required TRM values. It should not be required to perform many other studies to determine a TRM with the "maximum uncerttainty". |
| **Response:** We agree. The standard drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the chosen types of uncertainty from the list in the standard per the entity's TRM methodology. | | | |
| MEC<br>MRO | | ☑ | These studies should be coordinated as a NERC-wide activity outside of these standards. |
| **Response:** The standard drafting team appreciates the concern, and will request the Planning Committee develop a white-paper to provide the industry guidance on how to calculate TRM and uncertainty. | | | |
| Manitoba Hydro | | ☑ | I don't know what the value of a maximum uncertainty would be. Each uncertainty has a probabalitic component to it. It would be simple enough to add up all the uncertainites but if the probalistic analysis determined that the maximum uncertainty event was once every 10 years or once every 15 years, I do not know what value that would have. If the standard listed some assumptions, e.g. events that you expect to see within a 1 year or 3 year time frame, then this analysis could become more meaningful. |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** The standard drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the chosen types of uncertainty from the list in the standard per the entity's TRM methodology. | | | |
| SOCO | | ☑ | |
| Duke Energy | | ☑ | |
| FirstEnergy | | ☑ | |
| MEC Trading | | ☑ | |
| NPSI | | ☑ | |
| SERC ATCWG | | ☑ | Once the determination of TRM methodology has been identified, the TSP or TP or TC should use it to determine the required TRM values. It should not be required to perform many other studies to determine a TRM with the "maximum uncertainty". |
| **Response:** We agree. The standard drafting team feels that a maximum TRM would be the calculated amount of TRM in order to account for the chosen types of uncertainty from the list in the standard per the entity's TRM methodology. | | | |
| ITC | ☑ | ☑ | You only need to investigate TRM if there is evidence of overselling or underselling. The compliance monitor should be so instructed. TRM is dealing with uncertainty. How do you study uncertainty? You don't, you just observe it in real-time. |
| **Response:** Underselling and overselling is not covered by this standard; NERC is focused on ensuring that the TRM is calculated as the Transmission Operator has described in the methodology. Concerns regarding the actual values will need to be pursued through other venues. The standard drafting team believes some of this may be addressed in measures and compliance. We feel that it is possible for entities to calculate the amount of exposure to uncertainty they will experience and use those calculations to determine the amount of TRM they require to maintain reliability. | | | |
| ERCOT | ☑ | | Study should include using historic data to determine impact of actual versus forecasted information on loading of transmission system components that are limiting the TTCs or TFCs. |
| **Response:** The majority of commenters did not believe that a study should be required. Using historic data to determine the impact of actual versus forecasted information on loading of transmission system could be a valid method for determining the amount of uncertainty due to aggregate load forecast error. | | | |

6. Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If "Yes," please provide what you believe is an appropriate percentage in your response in the comments area.

**Summary Consideration:** Stakeholders who responded to this question indicated that the standard should not preclude nor require that a percentage of Facility Ratings be reserved as TRM. The standard drafting team believes that as long as the TRM is calculated based on the different types of uncertainty listed in R1.1 then it does not matter how that TRM is applied i.e. across interfaces or as a percentage of Facility Ratings. The proposed standard allows each entity to determine the appropriate TRM values for its own system.

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSC SC | | | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| Manitoba Hydro | | | I think that a percentage could be appropriate, but the best TRM value will always be one that is based on analysis of the potential uncertainties on a flowgate. I would hope that the committee will consider using a percentage as a default methodology, but allow for an analysis of uncertainties to modify the final value. A percentage would have to be based on flowgate capability. 5% may be a good default on a 100MW flowgate but overkil on a 1600MW flowgate. |
| **Response:** As long as the TRM is calculated based on the different types of uncertainty listed in R1.1 then it does not matter how that TRM is applied i.e. across interfaces or as a percentage of facility ratings. The proposed standard allows each entity to determine the appropriate TRM values for its own system. | | | |
| ERCOT | | ☑ | There is no technical justification of using 2 - 5% of Facility Rating as TRM. Since Facility Ratings are determined using conditions that are already worst case conditions, using additional safety factor results in underutilizing the transmission system. If uncertainties such as using first contingency conditions and using worst case scenarios for components that are used for ATC/AFC calculations already include uncertainties there should not be double counting of these uncertainties. If data can be supported by historic information, then only data should be used for setting aside TRM. |
| **Response:** The standard drafting team disagrees. We feel that TRM as a percentage of facility ratings is just as quantifiable as TRM across interfaces. Therefore even if an entity uses percentages of Facility Ratings as TRM they must still explain and provide the assumptions they used to arrive at the percentage value. | | | |
| HQT | | ☑ | TRM depends on system and path topology. |
| **Response:** The standard drafting team disagrees. We feel TRM depends on the different types of uncertainty that the system is exposed to. Therefore any of the different types of uncertainty listed in R1.1 can be used to determine TRM not just system and path topology. | | | |
| IESO<br>IRC SRC | | ☑ | We do not believe this approach duly addresses the various components of TRM which may change depending on the system conditions. However, we hold no position on individual entities who choose to apply this approach to determine the TRM. |
| **Response:** The standard drafting team feels that the different types of uncertainty outlined in the standard adequately | | | |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| addresses the various components of uncertainty that a system would be exposed to. Therefore in order to maintain consistency between transmission systems, the types of uncertainty defined in R1.1 are the only components that can be used to determine a system's TRM. | | | |
| MEC<br>MRO | | ☑ | No - some of the area Transmission Service Providers use a percentage and also provide for incremental power flows for reserve sharing. |
| **Response:** The TRM standard will continue to allow entities to use a percentage of facility ratings as TRM as long as they arrived at that percentage by using the different types of uncertainty listed in R1.1 which includes reserve sharing agreement. | | | |
| FirstEnergy | | ☑ | |
| MEAG | | ☑ | |
| NPSI | | ☑ | |
| SERC ATCWG | | ☑ | |
| SOCO | | ☑ | |
| APPA | ☑ | | If a percentage is used then it should be asked of the industry how large of a percentage is permitted before having to explain or provide the assumptions to arrive at the percent value. |
| **Response:** In general, we agree. However, we feel that TRM as a percentage of facility ratings is just as quantifiable as TRM across interfaces. Therefore even if an entity uses percentages of Facility Ratings as TRM they must still explain and provide the assumptions they used to arrive at the percentage value. | | | |
| BPA | ☑ | | While this methodology may be sufficient for several Transmission Service Providers (TSPs), it may not be for others. Therefore, use of this type of percentage should not be the only mechanism available for TSPs to determine TRM on their systems. |
| **Response:** The standard drafting team agrees. We feel that using a percentage of facility ratings is a valid way to account for uncertainty but by no means is the only way to account for uncertainty. | | | |
| ITC | ☑ | | 5% is appropriate. However, as we have stated before, it could change with observed system response. If you are using 5% and denying service with no TLRs or congestion, you may want to lower it. Compliance monitoring of this standard should (must) include this type of evaluation. Just picking a number only works if the real-time system response justifies it. |
| **Response:** The standard drafting team feels that TRM as a percentage of facility ratings is quantifiable by using the different types of uncertainty listed in R1.1. Therefore by calculating the uncertainty exposure each entity will arrive on the appropriate TRM value for its own system. The standard drafting team feels that monitoring TLRs or congestion on the system may be valid a way to validate TRM values but it is not necessarily the only way. | | | |
| WECC MIC MIS ATC TF | ☑ | | Two to five percent is acceptable. However, it should not be mandated as the single methodology allowed. Further, the TRM has multiple components, one of which is the Reserve Sharing Group component. The 2-5% is not appropriately applied to the Reserve Sharing Group subset of TRM; |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | rather, the 2-5% accurately applies only to the "uncertainty" portion of the TRM.<br><br>While this methodology may be sufficient for several TSPs, it may not be sufficient for others. Therefore, use of this type of percentage should not be the only mechanism available for TSPs to determine TRM on their systems. |
| **Response:** The standard drafting team had decided that as long as the TRM is calculated based on the different types of uncertainty listed in R1.1 then it does not matter how that TRM is applied i.e. across interfaces or as a percentage of facility ratings. We have also decided to let each entity to determine the appropriate TRM values for their own system. | | | |
| Duke Energy | ☑ | | |

7. Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

**Summary Consideration:** The drafting team has modified this requirement to more closely align with what is explicitly described in the pro-forma tariff section (attachment C paragraph D) of 890. R1.5 was modified as shown below:

**R1.5** If a ~~Transmission Planner or~~ Transmission Operator elects to utilize a TRM of ~~reserves~~ zero ~~(0) TRM in any~~ for all the time periods listed in R1.4 above, ~~time horizon,~~ that ~~Transmission Planner or~~ Transmission Operator shall ~~document~~ include a statement of that practice in its TRM ID ~~methodology the reason(s) why it did not reserve any TRM~~.

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSC SC | | | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| BPA | | | BPA may not calculate TRM on some of its constraints due to uncertainty components being included in those constraints' TFC determinations. Therefore, a TRM of "0 MW" would be posted and documented, per R1.5. of MOD-008-1. Would this practice meet the intent of this standard? |
| **Response:** We believe the answer to be yes, but compliance would have the final say. However if you have any suggestions how to make the requirement more clear, please provide them to the group. | | | |
| APPA | | ☑ | A zero TRM will provide more ATC for the use by the Transmission Customers. To make the TP or TOP post the reason they have determined that zero is the number is busy work and against good reliable practices. |
| **Response:** See summary consideration. | | | |
| ERCOT | | ☑ | R1.5 tends to imply that all Transmission Planner and Transmission Operators must use TRM, unless they can justify not using it. On the contrary, those TPs and TOs who use TRM should justify its use as use of TRM results in lower ATCs due to uncertainties that may already be included in determining the components that are used for ATC calculations. |
| **Response:** See summary consideration. | | | |
| HQT | | ☑ | TP or TO should only explain why it reserves non-zero TRM since it reduces the available capacity for the market. |
| **Response:** See summary consideration. | | | |
| NPSI | | ☑ | Explaination may divulge commercially sensitive or critical infrastructure information. |
| **Response:** See summary consideration. | | | |
| SOCO | | ☑ | It is unclear what benefit would be gained by requiring the Transmission Planner or Transmission Operator to supply this explanation. |
| **Response:** See summary consideration. | | | |
| SRP | | ☑ | This is unnecessary "busy work." FERC is concerned about TSP's hoarding transmission capacity by unjustifiably setting aside large quantities of TRM. If I set aside zero TRM this should make FERC |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | very happy because it frees up more ATC for purchase. By making me justify why I am setting aside zero TRM I am being encouraging to set aside non-zero TRM to avoid having to justify it. At the very least R1.5 should be rewritten to clarify precisely what circumstance require justification for zero TRM. For example, if I set aside zero TRM for only one hour on only one path do I have to explain why? Conversely, if I have zero TRM for all time periods and for all paths but one have I avoided the need to justy why I have zero TRM for the other paths? |
| **Response:** See summary consideration. | | | |
| IESO<br>IRC SRC | ☑ | ☑ | If a 0 MW TRM is reserved, it suggests that the TP and TOP are comfortable with the available control actions other than utilizing the transmission service reserved for TRM to address transmission uncertainties. On the other hand, the value of TRM reserved, including 0 MW, are subject to verification if need be. The question then becomes why 0 MW needs to be explained but not any other values? For example, other transmission users may question a high value of TRM reserved which reduces the ATC for use by others. |
| **Response:** See summary consideration. | | | |
| FirstEnergy | ☑ | | This explanation increases tranparency in the calculation process which is desired by FERC. |
| **Response:** See summary consideration. | | | |
| Duke Energy | ☑ | | The explanation should describe how reliability is maintained in light of the uncertainties identified in R1.1 |
| **Response:** See summary consideration. | | | |
| ITC | ☑ | | The justification is simple, no TLRs are observed and no market congestion is observed. If either symtom is present, TRM of zero is not justifiable. I.e, R1.5 is very easy to comply with. |
| **Response:** See summary consideration. | | | |
| MEC | ☑ | | Generally zero TRM is potentially providing inadequate protection for reliability. |
| **Response:** The standard drafting team feels that not all systems require the use of TRM, due to the fact that elements of uncertainty can be accounted for elsewhere in the calculation of ATC/TTC or AFC/TFC. | | | |
| MEC Trading | ☑ | | The reason for TRM is uncertainty. It is hard to believe that all of the ATC calculations are without uncertainty, so if uncertainty is buried in another part of the ATC calculation, it would be helpful to know where. |
| **Response:** See summary consideration. | | | |
| Manitoba Hydro | ☑ | | The analysis need not be extensive and based on past performance, however a 0 TRM allows the tranmission custmers access to a flowgate with no margin of error, and some thought should be put into that situation. |
| **Response:** The standard drafting team feels that not all systems require the use of TRM, due to the fact that elements of uncertainty can be accounted for elsewhere in the calculation of ATC/TTC or AFC/TFC. | | | |
| MRO | ☑ | | The MRO generally considers zero TRM as potentially providing inadequate protection for reliability. |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** The standard drafting team feels that not all systems require the use of TRM, due to the fact that elements of uncertainty can be accounted for elsewhere in the calculation of ATC/TTC or AFC/TFC. | | | |
| SERC ATCWG | ☑ | | |

8. Are there other legitimate needs for TRM that should be in the list described in R1? If "Yes," please explain your answer in the comments area.

**Summary Consideration:** None of the stakeholders who responded to this question identified other legitimate neds for TRM that should be described in R1. However, some stakeholders did recommend modifications to the list of uncertainties that must be documented. The standard drafting team has modified R1 to address stakeholder comments suggesting that the list of uncertainties should be expanded to include maintenance outages and the location of future generation. The other items proposed are either already addressed as written, or are addressed in other standards.

| **Question #8** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| NPSI | | | In the case of a system that is radially connected to other systems via a single interconnection will become islanded for a single contingency (loss of the interconnection). If the system was importing more than 10% (nominal) of its load at the time of the interconnection, the system will likely trigger Stage 1 under frequency load shedding. Therefore there must be a TRM facto that varies with system load to limit the amount of UFLS. In Nova Scotia, we set the import limit at 22% of total net load on our system to avoid Stage 2 UFLS for a single contingency. We use TRM as that variable (with additional margin for load forecast uncertainty. It is not clear if this need is addressed in this standard. Another need would be to share load following with our neighbour (AGC margin). For example, if NS and NB are jointly controlling the NB-New England tie, the NS-NB tie capacity must be held back from its TTC to allow room to respond to load and generation fluctuations (especially wind generation). The latter may be the intent of the R2 "Variations in generation dispatch". |
| **Response:** We believe that this should be handled more appropriately as an SOL that impacts the calculation of TTC, rather than including it in TRM. If there are concerns with equity and commercial needs, they would need to be addressed via NAESB business practices or coordination/allocation agreements. | | | |
| IESO<br>IRC SRC | | ☑ | None, but there appears to be two requirements that pertain to access to external generation that may be duplicated or in excess of the CBM value: they are aggregate load forecast error and reserve sharing requirements. We suggest the SDT to review the two lists to eliminate any duplication or excessive allocation. |
| **Response:** These are not duplicate values. Requirements 3.1.2, 3.2.1, and 3.3.1 of MOD 4 are intended to address the CBM/reserve sharing issue. Regarding Load Forecast error, there are different kinds of load forecast error – one is the operating (day to day) error, which should be used in TRM; the other is long-term error, which is used in generation planning and CBM. | | | |
| WECC MIC MIS ATC TF | | ☑ | However, the NERC Team should clarify that the uncertainties listed in R1.1 "may" be used in TRM calculations (as opposed to being required to be used). |
| **Response:** These are the only types of uncertainties that can be used in a TRM calculation. The language as written requires "Identification of (on each of its respective Posted Paths or Flowgates) each of the following components of uncertainty *if used* in calculating TRM," which we believe allows for the option to not use. | | | |
| Duke Energy | | ☑ | |

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| ERCOT | | ☑ | |
| FirstEnergy | | ☑ | |
| MEC Trading | | ☑ | |
| MEAG | | ☑ | |
| PSC SC | | ☑ | |
| SOCO | | ☑ | |
| ITC | ☑ | ☑ | We're dealing with uncertainty here. What is legitimate uncertainty? There are enough requirements to find something to use. |
| **Response:** Legitimate uncertainty is the uncertainty we list in R1.1. We agree that there are enough types of uncertainty to choose from in order to satisfy everyone's needs to account for their exposure to uncertainty. | | | |
| APPA | ☑ | | The SDT has not made it clear when energy can be scheduled on TRM capacity. |
| **Response:**<br>In general, TRM is not scheduled upon except in the case of reserves sharing (in which case it is tagged after the fact) or unless the TRM has been posted back as non-firm. | | | |
| HQT | ☑ | | 1. Variation of load (for daily, weekly, monthly and yearly ATCs)<br>2. Uncertainty about weather conditions (for daily, weekly, monthly and yearly ATCs)<br>3. Variation in facility loading (sufficient TRM should be maintained for deviations from load forecast due to balancing of generation within a control area )<br>4. Calculation Inaccuracies (Sufficient TRM should be assumed to account for the limitation of the TTC calculation method.) |
| **Response:** These uncertainties are accounted for in the present list of uncertainties. | | | |
| MEC | ☑ | | Maintenance Outages, Uncertainty in Location of future generation, and uncertainty in power transactions. Also, the Standards Drafting Team should clarify that the Reserve sharing requirements are "Incremental power flows for reserve sharing requirements or automatic sharing of reserves." |
| **Response:** The standard drafting team has made modifications to R1.1 to modify 'Variations in generation dispatch' to now state, 'Variations in generation dispatch (including maintenance outages and location of future generation' in support of your suggestion.<br>The other items we believe are already addressed as written. | | | |
| Manitoba Hydro | ☑ | | I believe that the need to hold back TRM for Inertial response is broad enough. Just as system load can degrade inertial response, system loading can degrade voltage response. I would recommend that initertial response be changed to include transient, dynamic, and voltage response. |
| **Response:** The uncertainty element of transient, dynamic, and voltage response variables should be covered under FAC- | | | |

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| 010. | | | |
| MRO | ☑ | | Maintenance Outages, Uncertainty in Location of future generation, and uncertainty in power transactions.  Also, the MRO requests that the Standards Drafting Team clarify that the Reserve sharing requirements are "Incremental power flows for reserve sharing requirements or automatic sharing of reserves." |
| **Response:** The standard drafting team has made modifications to address the concerns related to outages and future generation.  The other items we believe are already addressed as written. | | | |
| SERC ATCWG | ☑ | | |

9. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

**Summary Consideration:** The majority of commenters did not have concerns. The SDT notes that some entities may elect to pursue regional differences.

| Question #9 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| IESO | | ☑ | None, but it should be noted that some entities do not provide physical transmission services and therefore some of the requirements in this standard may not be applicable to them. |
| **Response:** The SDT understands your concerns, and notes that entities may elect to pursue regional differences. | | | |
| IRC SRC | | ☑ | None, but it should be noted that some entities do not provide physical transmission services and therefore some of the requirements in this standard may not be applicable to them. |
| **Response:** The SDT understands your concerns, and notes that entities may elect to pursue regional differences. | | | |
| NPSI | ☑ | ☑ | Tariffs and Market Rules may have to be updated to reflect the new requirements of MOD-008. |
| **Response:** We understand that some entities may need to make such changes. | | | |
| MEC Trading | ☑ | | This appears to be a fill-in-the-blank standard. |
| **Response:** Because different entities experience different amount of uncertainty, flexibility is required in this standard in order to account it in each area. For example, some entities experience much larger loop flows through their system than other entities. | | | |
| Duke Energy | | ☑ | |
| ERCOT | | ☑ | |
| FirstEnergy | | ☑ | |
| ITC | | ☑ | |
| MEC | | ☑ | |
| Manitoba Hydro | | ☑ | |
| MRO | | ☑ | |
| PSC SC | | ☑ | |
| WECC MIC MIS ATC TF | | ☑ | |
| SOCO | | ☑ | |

10. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

**Summary Consideration:** Based on stakeholder comments, the drafting team made the following modifications to the standard:

- Removed the requirements to make documents publicly available (R7 and R10). The drafting team has been working closely with NAESB and NAESB confirmed it will address all posting requirements in its business practices
- Removed R4 which required the Load-serving Entity to refrain from using the components of uncertainty identified in the determination of TRM to determine the Load-serving Entity's CBM MW import requirement. If a requirement is needed for this, that requirement should be in the standard covering CBM (MOD-004)
- Modified R8 (R4 in the revised standard) to be more explicit in who it applies to and the method of requesting the information
- Revised the Purpose statement by replacing the phrase "to help ensure more accurate calculation of transfer capabilities" with "for reliable system operations"
- Corrected the typographical error in R1.1 to add the missing word, 'of' after the word, 'Identification'
- Added the words, 'of a documented request' to R8 (R4 in the revised standard)
- Adopted the proposed definition of 'Posted Path' which is already used by FERC
- Added the word, 'Posted' in R5 to change 'Path' to 'Posted Path'
- Absorbed R2 into R1 and eliminated the reference to 'Contract Path'
- Deleted R11

<table>
<tr><th colspan="2">Question #10</th></tr>
<tr><th>Commenter</th><th>Comment</th></tr>
<tr><td>Duke Energy</td><td>The "make publically available" Requirements R7 and R10 are inappropriate for NERC standards. These are communications which should be in the NAESB standards.</td></tr>
<tr><td colspan="2">Response: The standard drafting team did work with NAESB and determined that all of the posting requirements will be in NAESB business practices. The drafting team removed Requirement 10 (which required the Transmission Service Provider to make its TRM values publicly available) from the revised standard.</td></tr>
<tr><td>FirstEnergy</td><td>R4 is contained in the revised MOD-004-1 provided with this SAR packet as R14. R4 us a duplicate requirement and should be deleted from MOD-008-1.<br><br>The request referenced in R8 shoud be required to be in writing as a means of formally documenting the request was made, received, and acknowledged.</td></tr>
<tr><td colspan="2">Response: The standard drafting team has deleted R4 from this standard. We have modified R8 to be more explicit in who it applies to and the method of requesting the information. The revised requirement (R4 in the revised standard) uses the phrase, '. . . within seven calendar days of a documented request for such information. . ' in support of your suggestion.</td></tr>
</table>

| Question #10 | |
|---|---|
| **Commenter** | **Comment** |
| IESO | Requirement 1.1 should not only include generation dispatch variations but also peak and off peak dispatch variations. Additionally, Requirement 1.1 – the first line "Identification any of the following…" should be written to read as "Identification of any of the following…"<br>We have provided similar comments on the supplementary SAR, MOD-001 and MOD-004. The SAR for revising and creating this set of standards has not gone through prior public review and comment on the need and direction for these standards. It is posted simultaneously with the revised standard, making posting of the SAR irrelevant. Yet the revised standards appear to be uncoordinated, duplicated and convoluted in some.<br>We understand these standards need to be revised to meet the FERC's timeline but they should be done in a proper and orderly manner to ensure manageability not just by the staff and the SDT but also by the stakeholders in the industry. We do not agree with the process, and we do have trouble reviewing the set of standards that in our view are not well structured (for example: combining all 4 standards MOD-004 to MOD-007 into one). There has been no industry input process that either supports or disagrees with this proposed combining before the standards are drafted and posted.<br>And some of the standards assign responsibilities to entities that should not be responsible for some of the tasks. For example, the RC and PC are not responsible for calculating ATC. The proposed intent to combine some of the MODs as one includes the RC and PC in these standards because of the TTC calculation requirements. But in doing so, the assignment of tasks and responsibilities becomes confusing resulting in these entities being assigned some tasks inappropriately.<br>We suggest the SDT to revise the supplementary SAR and post it for comments, with sufficient detail and specificity on the proposed scope and structure of the standard set, before drafting/revising the standards. |

**Response:**

We believe that "peak and off peak dispatch variations" are covered already in generation and load variations.

We changed R1.1 to "identification of … each of the following".

We recognize the concern expressed by the IESO related to the SAR. However, we are attempting to both address the needs of the industry and the need to comply with the FERC Order, and felt this was the best way to meet both the requirements of the NERC process and be responsive to the Commission. Note that a SAR sets the scope of the technical content of the work, but leaves the structure of the actual standards to the Drafting Team's discretion. The Reliability Standards Development Procedure does allow the simultaneous posting of a SAR and its associated standard or standards.

The drafting team refined the applicability of each standard, based on stakeholder comments and a thorough review of the latest approved version of the Functional Model, and there were several places where the applicability was revised to eliminate the Planning Coordinator and Reliability Coordinator. The drafting team has revised the standards to state more explicitly which functional entity is responsible for each requirement.
Most stakeholders who commented on the SAR indicated support for the SAR as written so the drafting team did not make

| Question #10 | |
|---|---|
| **Commenter** | **Comment** |
| significant changes to the SAR. The comments on the SAR and the drafting team's responses to those comments have been publicly posted. | |
| IRC SRC | We have provided similar comments on the supplementary SAR, MOD-001 and MOD-004. The SAR for revising and creating this set of standards has not gone through prior public review and comment on the need and direction for these standards. It is posted simultaneously with the revised standard, making posting of the SAR irrelevant. Yet the revised standards appear to be uncoordinaed, duplicated and convoluted in some.<br>We understand these standards need to be revised to meet the FERC's timeline but they should be done in a proper and orderly manner to ensure manageability not just by the staff and the SDT but also by the stakeholders in the industry. We do not agree with the process, and we do have trouble reviewing the set of standards that in our view are not well structured (for example: combining all 4 standards MOD-004 to MOD-007 into one). There has been no industry input process that either supports or disagrees with this proposed combining before the standards are drafted and posted.<br>And some of the standards assign responsibilities to entities that should not be responsbile for some of the tasks. For example, the RC and PC are not responsible for calculating ATC. The proposed intent to combine some of the MODs as one includes the RC and PC in these standards because of the TTC calculation requirements. But in doing so, the assignment of tasks and responsibilities becomes confusing resulting in these entities being assigned some tasks inappropriately.<br>We suggest the SDT to revise the supplementary SAR and post it for comments, with sufficient detail and specificity on the proposed scope and structure of the standard set, before drafting/revising the standards. |
| **Response:** We recognize the concern expressed by the IRC related to the SAR. However, we are attempting to both address the needs of the industry and the need to comply with the FERC Order, and felt this was the best way to meet both the requirements of the NERC process and be responsive to the Commission. Note that a SAR sets the scope of the technical content of the work, but leaves the structure of the actual standards to the Drafting Team's discretion. The Reliability Standards Development Procedure does allow the simultaneous posting of a SAR and its associated standard or standards.<br><br>The drafting team refined the applicability of each standard, based on stakeholder comments and a thorough review of the latest approved version of the Functional Model, and there were several places where the applicability was revised to eliminate the Planning Coordinator and Reliability Coordinator. The drafting team has revised the standards to state more explicitly which functional entity is responsible for each requirement.<br>Most stakeholders who commented on the SAR indicated support for the SAR as written so the drafting team did not make significant changes to the SAR. The comments on the SAR and the drafting team's responses to those comments have been publicly posted. | |
| ITC | As we have stated before, all compliance and measures should be based on evidence of overselling or underselling. Otherwise its just bureaucratic red-tape. |
| **Response:** The purpose the NERC standards is to maintain reliability. | |
| MEC | 1. The purpose of each of the standards should be revised to be more in-line. The purpose in this standard be revised by replacing "to help ensure more accurage calculation of transfer capabilities" with "for reliability system |

| Question #10 | |
|---|---|
| **Commenter** | **Comment** |
| | operations."<br>2. The Standards Drafting Team has defined a scheduling horizon in addition to an operating horizon and a planning horizon. Why did the Standards Drafting Team establish it and why have they defined it as provided in the standard. |
| **Response:** The standard drafting team agrees and has revised the purpose of the standard to include the phrase, 'for reliable system operations' in support of your suggestion.<br><br>The standard drafting team has eliminated the term "horizons," but elected to include time periods specified by the FERC that apply to the standards. | |
| MRO | 1. The purpose of each of the standards should be revised to be more in-line. The MRO recommends that the purpose in this standard be revised by replacing "to help ensure more accurage calculation of transfer capabilities" with "for reliability system operations." 2. The MRO notes that the Standards Drafting Team has defined a scheduling horizon in addition to an operating horizon and a planning horizon. The MRO is not familiar with the use of a scheduling horizon and questions why the Standards Drafting Team established it and why they have defined it as provided in the standard. |
| **Response:** The standard drafting team agrees and has revised the purpose of the standard to include the phrase, 'for reliable system operations' in support of your suggestion.<br>The standard drafting team has eliminated the term "horizons," but elected to include time periods specified by the FERC that apply to the standards. | |
| WECC MIC MIS ATC TF | A. Reiterating comments from MOD-04 CBM, the Team suggests the following CBM definition replace the existing CBM and TRM NERC definitions:<br>"Capacity Benefit Margin"<br>CBM is the amount of firm import transmission capability, requested by the LSE, to exclusively serve identified load only during periods of emergency generation deficiencies extending beyond the beginning of the scheduling hour in which the emergency generation deficiency occurs."<br>B. Typo on the first line of R1.1. Should state: "Identification of any of the following…"<br>C. R8. Add: "Each Transmission Service Provider shall make available (within seven CALENDAR days OF A REQUEST)… (Emphasis added.)<br>D. As previously stated, there is an existing FERC approved definition for Posted Path that should be included in the NERC Glossary and utilized in the ATC standards.<br>R10. The term Posted Path should be used as a defined term.<br>The definition for Posted Path should be as follows:<br>Posted Path<br>Posted Path means: 1) any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour |

| Question #10 | |
|---|---|
| **Commenter** | **Comment** |
| | during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.<br>E. R5. Should read "…(on each POSTED PATH or Flowgate)…<br>F. R2. At minimum, the word "Contract Path" should be deleted as the intent is to cover all Posted Paths. This Team continues to suggest the adoption of the CFR defined term "Posted Path" that is the more accurate usage for this R.<br>G. R11. Should be reworded as neither the Transmission Planner nor the Transmission Operator "reserve capacity" on their system(s). That's not within their Functional Model purview. The Transmission Planner and the Transmission Operator can identify capacity that "should be reserved" on their system(s); however, the Transmission Service Provider is the accurate entity to actually "reserve" the capacity. |

**Response:**

A. The drafting team did not adopt the proposed definition of CBM as there is already an approved definition of CBM.
B. The typographical error in R1.1 was corrected.

C. The drafting team added the words, 'of a documented request' to R8 (R4 in the revised standard)

D. The drafting team adopted the proposed definition of Posted Path.

E. R5 – the word, 'Posted' was inserted in front of 'Path' as suggested

F. R2 was absorbed into R1 and the reference to 'Contract Path was eliminated as suggested.

G. R11 was deleted as suggested.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a standard drafting team on March 17, 2006.

**Description of Current Draft:**

This is the first draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR with consideration of applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Respond to comments. | TBD |
| 2. Post revised standard for stakeholder comment. | TBD |
| 3. Respond to comments. | TBD |
| 4. Post for 30-day pre-ballot review. | TBD |
| 5. First ballot of standard. | TBD |
| 6. Respond to comments. | TBD |
| 7. Recirculation ballot. | TBD |
| 8. 30-day posting before board adoption. | TBD |
| 9. Board adoption. | TBD |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Available Flowgate Capability (AFC):** A measure of the capability remaining in the Flowgate for further commercial activity over and above already committed uses. It is equal to the Total Flowgate Capability less the impacts of existing Transmission commitments (including retail customer service), less the impacts of Capacity Benefit Margin and less the impacts of Transmission Reliability Margin.

**Flowgate:** A single transmission element, or a group of transmission elements, or a single transmission element with one or more contingencies, or a group of transmission elements with one or more contingencies, intended to model MW flow impact relating to transmission limitations and transmission service usage.

**Total Flowgate Capability (TFC):** The amount of electric power that can flow across the Flowgate under specified system conditions without exceeding the capability of the Facilities. Typically expressed in the form of thermal capability. Flowgates can be proxies for Stability and other limiting criteria.

**Transmission Reservation:** A reservation is a confirmed Transmission Service Request.

**Transmission Service Request:** A service requested by the Transmission Customer to the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.

## A. Introduction

1. **Title:** **Capacity Benefit Margin**

2. **Number:** MOD-004-1

3. **Purpose:** To promote the consistent and transparent calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to ensure accurate calculation of reliable transfer capabilities.

4. **Applicability:**

   **4.1. Functional Entity:**

   **4.1.1** Load-Serving Entity that is entitled and would like to have transmission capability set aside in the form of CBM to maintain resource adequacy requirements.

   **4.1.2** Transmission Service Provider.

   **4.1.3** Balancing Authority.

   **4.1.4** Transmission Planner.

5. **Facility Limitations/Specifications:**

   **5.1.** None.

6. **Proposed Effective Date:** To be determined.

## B. Requirements

**R1.** The Transmission Service Provider shall make publicly available:

**R1.1.** Its procedure for a Load-Serving Entity to request its CBM import MW requirement on each Point of Receipt — Point of Delivery (POR-POD) combination (path) for meeting its resource adequacy requirement (i.e., its procedure for setting aside of Transfer Capability in the form of CBM to maintain a Load-Serving Entity's resource adequacy requirement).

**R1.2.** Its procedure and assumptions for allocating CBM over each path or Flowgate.

**R1.3.** Its procedure for CBM use (i.e., its procedure for scheduling of energy over transmission capacity set aside as CBM).

**R1.4.** The most recent values of CBM used for calculating Available Transmission Capacity (ATC) or Available Flowgate Capability (AFC) for each timeframe by Flowgate or path, as applicable.

**R2.** The Transmission Service Provider shall make publicly available copies of the models used for allocating CBM over each path or Flowgate within seven calendar days following a request by an entity with a valid need for such information.

**R3.** The Transmission Service Provider shall determine CBM for the purpose of calculating ATC or AFC for each POR-POD combination (path) as follows:

**R3.1.** The Transmission Service Providers that uses the Network Response Methodology for determining Total Flowgate Capability shall allocate CBM to each Flowgate based on the distribution factor for the POR to the POD multiplied by the quantity of CBM import MW requirement on each POR-POD combination (path) requested.

**R3.1.1.** The Transmission Service Provider shall use the same methodology as used for its Existing Transmission Commitments (ETC) calculation for accounting for counter-flow when CBM is requested from multiple PORs.

**R3.1.2.** The Transmission Service Provider shall not include transmission capacity set aside for reserve sharing in CBM.

**R3.2.** The Transmission Service Provider that uses the Rated System Path Methodology for determining Total Transfer Capability shall use the algebraic sum of all valid CBM requests for that specific path as the CBM for that path.

**R3.2.1.** The Transmission Service Provider shall not include transmission capacity set aside for reserve sharing in CBM.

**R3.3.** The Transmission Service Provider that uses the Network Response Methodology for determining Total Transfer Capability shall use the algebraic sum of all valid CBM requests for that specific path as the CBM for that path.

**R3.3.1.** The Transmission Service Provider shall not include transmission capacity set aside for reserve sharing in CBM.

**R3.4.** The Transmission Service Provider shall use "zero" as the value for all unscheduled CBM for all non-firm ATC calculations for all methodologies.

**R4.** The Load-Serving Entity that wants CBM allocated for its potential use shall submit, (at least annually) a request for its CBM import MW requirement (i.e., a request for setting aside of Transfer Capability in the form of CBM to maintain the Load-Serving Entity's resource adequacy requirement) to its Transmission Service Provider and Balancing Authority documenting the quantity of CBM import MW requirement to which the Load-Serving Entity is entitled based upon verifiable historical, state, Regional Transmission Organization, regional, or other resource adequacy criteria. The request shall be accompanied by a report (CBM Import Entitlement Report), which shall include:

> See paragraph 1077 of FERC Order 890: "…. We also clarify that CBM should only be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. We expect verification of the CBM values to be part of the Requirements with appropriate Measures and Levels of Non-Compliance."

**R4.1.** Identification of the Load-Serving Entity

**R4.2.** Projected CBM import MW requirement for each POR-POD combination (path) for each year for the next ten-year period.

**R4.3.** Identification of the entity responsible for establishing the Load-Serving Entity's resource adequacy requirements.

**R4.4.** Identification of all applicable reserve margin and resource adequacy requirements for the Load-Serving Entity.

**R4.5.** Summary of results of resource studies performed to determine the quantity of CBM, not to include confidential information.

**R5.** The Load-Serving Entity shall document and retain the following information for a period of five years:

**R5.1.** Projected CBM import MW requirement for each POR-POD combination (path) for each year for the next ten-year period.

**R5.2.** Documentation identifying the municipality, state commission, Regional Transmission Organization/Independent System Operator, Regional Reliability Organization, or Regional Entity responsible for establishing the Load-Serving Entity's resource adequacy requirements.

**R5.3.** Copies of all applicable reserve margin and resource adequacy requirements to include one or more of the following:

- Municipality generation reserve margin and resource adequacy requirements
- State generation reserve margin and resource adequacy requirements
- Regional Transmission Organization/Independent System Operator generation reserve margin and resource adequacy requirements
- Regional Reliability Organization reserve margin and resource adequacy requirements

**R5.4.** Copies of all resource planning studies performed to determine the Load-Serving Entity's quantity of CBM to include one or more of the following:

- Loss of load expectation (LOLE) studies/loss of load probability (LOLP) studies
- Loss of largest unit studies
- Other reliability resource adequacy studies utilized by a Load-Serving Entity in establishing its CBM import MW requirements.

**R6.** The Load-Serving Entity that uses probabilistic studies for determining the CBM import MW requirement on each POR-POD combination (path) shall:

**R6.1.** Identify and use the criteria required by the Load-Serving Entity's documented resource adequacy requirements (e.g., the LOLE value is 1 day in 10 years, or 1 event in 10 years).

**R6.2.** Identify and use load assumptions (e.g., a load forecast that has a 50% probability of occurrence) in the study that are the same as the load assumptions used to determine the Load-Serving Entity's resource adequacy requirements.

**R6.3.** Identify all resources committed to serve the Load-Serving Entity's load, including:

**R6.3.1.** Generators within the Load-Serving Entity's area with Designated Network Resource (DNR) status.

**R6.3.2.** Generators with Capacity contracts to serve load within the Load-Serving Entity's area.

**R6.3.3.** Generators external to the Load-Serving Entity's area with firm Transmission Reservations to the Load-Serving Entity's area.

**R6.3.4.** Firm capacity backed transaction contracts with external entities with firm Transmission Reservations to the Load-Serving Entity's area.

**R6.4.** Identify all resources in the Load-Serving Entity's area excluded from serving the Load-Serving Entity's load, including:

**R6.4.1.** Generation within the Load-Serving Entity's area with firm contracts to serve load outside the Load-Serving Entity's area.

**R6.4.2.** Uncommitted generation within the Load-Serving Entity's area including uncommitted Independent Power Producers' resources.

**R6.5.** Use forced outage rates to represent generation unit availability that are the same as the forced outage rates used to determine the Load-Serving Entity's resource adequacy requirements.

**R6.6.** Use firm system purchases that are the same as the firm system purchases used to determine the Load-Serving Entity's resource adequacy requirements.

**R6.7.** Identify the treatment of the following:

**R6.7.1.** Forced outage rates for new units.

**R6.7.2.** Generator seasonal ratings.

**R6.7.3.** Projected generator maintenance schedules.

**R6.7.4.** Fuel, wind, hydro or other reasons which may limit dispatch of a resource.

**R6.7.5.** Common mode outages that effect resource adequacy.

**R6.7.6.** Availability of resources with environmental or regulatory restrictions.

**R6.8.** Identify exceptions to R6.1 thru R6.7 permitted by the entity responsible for the Load-Serving Entity's resource adequacy requirements.

**R7.** The Transmission Service Provider shall determine if transmission capability is available to meet a request for CBM import MW requirement on each POR-POD combination (path) within 30 calendar days of receiving the request and CBM Import Entitlement report identified in R4.

**R7.1.** The Transmission Service Provider shall set aside Transfer Capability in the form of CBM to maintain a Load-Serving Entity's resource adequacy requirement on its transmission system for each Load-Serving Entity that submits a request for CBM transmission capacity in an amount equal to or less then the amount its transmission system can accommodate.

**R7.2.** The Transmission Service Provider shall pro-rate all requests for CBM transmission capacity if the requests for CBM for a POR-POD combination (path) exceed the amount its transmission system can accommodate for that specific POR-POD combination (path) and shall set aside Transfer Capability in the form of CBM to maintain the Load-Serving Entity's pro-rated requests.

**R7.3.** The Transmission Service Provider shall provide to a Load-Serving Entity's Transmission Planner and make publicly available, the CBM Import Entitlement report provided by a Load-Serving Entity as required in R4.

**R8.** The Load-Serving Entity may request the scheduling of energy over transmission capacity set aside as CBM up to an amount equal to that determined under R7 as required by the Transmission Service Provider's procedure pursuant to R1.3.

**R8.1.** In the event CBM was reduced pursuant to R7.2, the Load-Serving Entity is still entitled to the full CBM import MW requirement on a POR-POD combination (path) requested when scheduling of energy over transmission capacity set aside as CBM

**R9.** The Balancing Authority shall waive the timing and ramping requirements for scheduling of energy over transmission capacity set aside as CBM.

**R10.** The Load-Serving Entity shall declare a NERC Energy Emergency Alert (EEA) 2 and initiate all steps in EEA 2 prior to scheduling of energy over transmission capacity set aside as CBM.

**R11.** The Load-Serving Entity shall provide a report to its Transmission Service Provider within 7 calendar days after the scheduling of energy over transmission capacity set aside as CBM and retain for a period of five years:

**R11.1.** Circumstances under which a NERC EEA 2 was declared and all steps initiated in EEA 2 before energy was scheduled over transmission capacity set aside as CBM.

**R11.2.** Amount of CBM capacity used and energy scheduled over transmission capacity set aside as CBM.

**R11.3.** Start and stop times of when energy was scheduled over transmission capacity set aside as CBM.

**R12.** The Transmission Service Provider shall make publicly available (for a period of one year) the report prepared by a Load-Serving Entity pursuant to R11 beginning within 7 calendar days after receiving the report.

**R13.** The Transmission Planner shall include all valid requests and projected CBM import MW requirements for each POR-POD combination (path) for each year for the next ten-year period, based on the information supplied in the Load-Serving Entities requests and as required in R4.1, in its planning process.

**R14.** The Load-Serving Entity shall not incorporate any of the components of uncertainty identified in Reliability Standard MOD-008-1 R1.1 into its determination of its CBM import MW requirement.

## C. Compliance

To be added with next posting.

## D. Measures

To be added with next posting.

## E. Regional Differences

None identified.

## F. Associated Documents

### Version History

| Version | Date | Action | Change Tracking |
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Please use this form to submit comments on the 1st draft of standard MOD-008-1 Transmission Reliability Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculations and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Transmission Reliability Margin (TRM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-008-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations. Please review the 'White Paper' and the proposed MOD-008 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "TRM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-008-0 and MOD-009-0 into the draft MOD-008-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team’s decision to combine all the requirements for Transmission Reliability Margin determination, verification, and use into a single standard? If “No,” please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission’s (FERC) Orders 890 and 693 related to TRM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC’s directives in FERC Orders 890 and 693 related to TRM in this draft of MOD-008-1? If “No,” please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-008-1 standard and expanded the applicability section of the TRM standard to include all applicable entities. Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☐ No

   Comments:

4. The drafting team created new TRM requirements and expanded or deleted some prior TRM requirements. Do you agree with the requirements identified in the draft standard MOD-008-1? If “No,” please explain why in the comment area.

   ☐ Yes

   ☐ No

   Comments:

**5.** Requirement R1.1 lists the uncertainties for which TRM may be set aside. Should studies be required to determine a “maximum uncertainty” to support the validity of a TRM value? If “Yes,” please explain what kinds of studies should be performed for any or all of the uncertainties in your response in the comments area.

☐ Yes

☐ No

Comments:

**6.** Several Transmission Service Providers use a percentage of Facility Rating for the TRM preserved for reliability (typically 2–5%). Do you believe that a percentage of Facility Ratings reserved as TRM is sufficient to maintain adequate reliability for all ATC calculations? If “Yes,” please provide what you believe is an appropriate percentage in your response in the comments area.

☐ Yes

☐ No

Comments:

**7.** Do you agree with the necessity of R1.5, which requires any Transmission Planner or Transmission Operator who reserves zero (0) TRM in any time horizon to explain why? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**8.** Are there other legitimate needs for TRM that should be in the list described in R1? If “Yes,” please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**10.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-008-1.

Comments:

# References to Capacity Benefit Margin in FERC Orders

## *From FERC Order 890*

***From Page 1045:***

**§ 37.6 Information to be posted on the OASIS**.

(vii) Capacity Benefit Margin or CBM means the amount of TTC preserved by the Transmission Provider for load-serving entities, whose loads are located on that Transmission Provider's system, to enable access by the load-serving entities to generation from interconnected systems to meet generation reliability requirements, or such definition as contained in Commission-approved Reliability Standards.

***Starting on Page 157:***

### (3) Capacity Benefit Margin (CBM)

**NOPR Proposal**

248. In the NOPR, the Commission proposed three options to address the CBM component of ATC: (1) have NERC develop clear standards for how the CBM value should be determined, allocated across transmission paths, and used; (2) charge an entity for which transfer capability has been set aside to meet generation reliability criteria a separate rate for this service; or (3) eliminate CBM and require an entity reserving ATC to meet generation reserve (currently through CBM) to designate network resources on the other side of the interface and make an associated transmission service reservation.

**Comments**

249. Numerous commenters support the Commission's proposed option one, requiring NERC to develop clear standards for how the CBM value should be determined, allocated across transmission paths, and used.[173] They believe that CBM ensures the ability to import needed power to support system conditions. TVA argues that option two would be costly and may cause some systems to forego CBM, thereby jeopardizing service to native load customers. PJM states that option two is irrelevant in PJM since PJM "totals" reservations and decides when CBM can be used. Supporters of option one criticize option three, elimination of CBM, as costly and a threat to transmission system reliability. Southern, Progress Energy, and PJM emphasize that, without CBM, the LSEs would need to increase their reserve margin by contracting for additional generation

[173] E.g., Allegheny, Ameren, EEI, Duke, NRECA, TVA, APPA, Bonneville, EPSA, FirstEnergy, Indianapolis Power, MidAmerican, Pinnacle, PJM, PGP, PNMTNMP, Public Power Council, Sacramento, Seattle, South Carolina E&G, TANC, TDU Systems, and Wisconsin Electric.

capacity, costing millions of dollars. In addition, Ameren and TVA believe that CBM elimination will increase the likelihood of widespread blackouts in emergency conditions.

250. At the October 12 Technical Conference, Exelon supported option two proposing a charge for CBM. Exelon contended that, in a rate-making context, there would be an increase in the divisor of the rate by the amount of CBM set-aside which would lower the point-to-point charge. Consequently, those not benefiting from the CBM set-aside effectively would be paying a lower charge.

251. Constellation and Morgan Stanley support the elimination of CBM and argue thatCBM and TRM are often used interchangeably and result in duplicative transmission set-asides. They also argue that there is no compelling need for CBM in the current liquid market environment. In addition, Morgan Stanley states that LSEs affiliated with the transmission provider should not be allowed to use CBM for long-term planning purposes as an excuse to avoid undertaking needed resource additions or to conceal the true cost of their load serving functions. Furthermore, the Commission should not be distracted by assertions that such long-term arrangements are necessary for "reliability," when in fact they are simply a way to protect the economic interests of a particular entity.

252. Duke replies that Constellation mistakenly believes that CBM is currently only available to a transmission provider's native load when, in fact, for those transmission providers that establish CBM, it should be established for the load of all LSEs in the control area. Duke contends that not all transmission providers set aside capacity through CBM for their native load; to the extent that a transmission provider does not set aside CBM, there should be no obligation to allow other LSEs to do so. Duke proposes that the Commission should continue to permit such flexibility.

253. NERC takes no position on CBM, expecting that the issue can be settled through the NERC and NAESB Procedure for Joint Standards Development and Coordination and through other open forums.

254. TAPS suggests that the Commission ensure that all LSEs have both access to CBM to meet their reserve-sharing needs and meaningful input into how much CBM is reserved. To do so, TAPS recommends the creation of a reserve-sharing group made up of the transmission provider and LSEs it serves. It argues that this would remove reservation decisions from the sole discretion of the vertically-integrated transmission provider and instead have them made by the transmission provider/LSE reserve-sharing group, subject to dispute resolution at the Commission. All LSEs would be invited to participate in the studies as well as review the results and assumptions. Moreover, once a regional planning process is established, as proposed in the NOPR, TAPS recommends that the regional planning group be required to approve the CBM reservation as well.

255. Williams suggests that a transmission provider must designate network resources and reserve firm transfer capability on both sides of the control area transmission

interface in order to reserve CBM. Duke replies that, although some commenters prefer eliminating CBM and replacing it with additional designated network resources, CBM is the preferable option because it is less costly. Duke further argues that the choice is between setting aside both additional transmission and generation capacity to deal with emergencies (the additional designated network resource approach) versus setting aside only transmission (the CBM approach). Having to procure additional designated network resources to keep in reserve reduces one of the main benefits of interconnected operations. Duke argues that eliminating CBM would drive up costs for network customers, as they would have to procure additional generation and transmission resources. EEI adds that such a proposal may result in increased LSE reserve requirements, over-building of generation supply, and a reduction, rather than an increase, in ATC.

**Commission Determination**

256. The Commission concludes that it is appropriate to allow LSEs to retain the option of setting aside transfer capability in the form of CBM to maintain their generation reliability requirement. We agree with commenters that, without CBM, LSEs would have to increase their generation reserve margins by contracting for generation capacity, which may result in higher costs without additional reliability benefits. We require, however, the development of standards for how CBM is determined, allocated across transmission paths, and used in order to limit misuse of transfer capability set aside as CBM. Transmission providers also must reflect the set-aside of transfer capability as CBM in the development of the rate for point-to-point transmission service to ensure comparable treatment for point-to-point to customers.

257. The Commission therefore adopts a combination of the NOPR options one and two, and declines to adopt option three. First, we require public utilities, working through NERC and NAESB, to develop clear standards for how the CBM value shall be determined, allocated across transmission paths, and used. We understand that NERC has already begun the process of modifying several of the CBM-related reliability standards and that the drafting process is a joint project with NAESB. Second, we require transmission providers to reflect the set-aside of transfer capability as CBM in the development of the rate for point-to-point transmission service.

258. We note that there is broad concern that eliminating CBM (option three) would impose extraordinary costs for meeting generation reliability criteria, which then may lead utilities to reduce their generation reliability requirement to avoid the cost increase. We believe that the reforms reflected in combining options one and two are sufficient to remedy undue discrimination and that the adverse effects associated with option three are neither warranted nor required. We reject Morgan Stanley’s call for CBM elimination on the grounds that CBM is acting as a disincentive to undertake needed generation resource additions. It would be inappropriate for the Commission to restrict the ability of an LSE to determine how best to meet its generation reliability criteria.

259. To ensure CBM is used for its intended purpose, CBM shall only be used to allow an LSE to meet its generation reliability criteria. Consistent with Duke's statement, we clarify that each LSE within a transmission provider's control area has the right to request the transmission provider to set aside transfer capability as CBM for the LSE to meet its historical, state, RTO, or regional generation reliability criteria requirement such as reserve margin, loss of load probability (LOLP), the loss of largest units, etc.

260. We direct public utilities, working through NERC, to develop clear requirements for allocating CBM over transmission paths and flowgates. While we do not mandate a particular methodology for allocating CBM to paths and flowgates, one approach could be based on the location of the outside resources or spot market hubs that an LSE has historically relied on during emergencies resulting from an energy deficiency.

261. We concur with TAPS' proposal that all LSEs should have access to CBM and meaningful input into how much transfer capability is set aside as CBM. In the transparency section below, we provide detailed requirements regarding availability of documentation used to determine the amount of transfer capability to be set aside as CBM and the posting of CBM values and narratives. Access to this documentation will enable LSEs to validate how much transfer capability is set aside as CBM on each system and provide them with information to question whether the set-aside is consistent with the reliability standards and this Final Rule.

262. Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage.

263. We also require transmission providers to design their transmission charges to ensure that the class of customers not benefiting from the CBM set-aside, i.e., point-to-point customers, do not pay a transmission charge that includes the cost of the CBM setaside. To do this, transmission providers are required to submit redesigned transmission charges that reflect the CBM set-aside through a limited issue FPA section 205 rate filing as part of its initial ATC-related compliance filing. These filings, which may be submitted within 120 days after the publication of the Final Rule in the Federal Register, may be limited to the rate design change only, i.e., they will not require the submission of cost of service data or a revision to the transmission provider's revenue requirement.

264. With respect to TAPS' proposal that all LSEs should be allowed to use CBM to meet their reserve-sharing needs, we believe that TRM is the appropriate category for that purpose, not CBM. We reject TAPS' proposal to use CBM for the LSE's reserve-sharing needs, but instead make TRM available for the incremental power flows resulting from reserve sharing, as explained next.

265. As we are rejecting option three, which would have required the reservation of transfer capability rather than using CBM, we also reject Williams' proposal to require the reservation of transfer capability on both sides of an interface for CBM.

## ***From FERC Order 693***

***Starting on Page 293:***

### f. Documentation of Regional Reliability Organization Capacity Benefit Margin Methodologies (MOD-004-0)

1067. MOD-004-0 requires each regional reliability organization to: (1) develop and document a regional CBM[174] methodology in conjunction with its members and (2) post the most recent version of its CBM methodology on a website accessible by NERC, regional reliability organizations and transmission users.

1068. In the NOPR, the Commission identified MOD-004-0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and document a regional CBM methodology. The NOPR stated that because the regional CBM methodologies had not been submitted, the Commission would not propose to approve or remand MOD-004-0 until the ERO submits the additional information.

1069. Although not proposing any action, the Commission nonetheless indicated that MOD-004-0 could be improved by: (1) providing more specific requirements on how CBM should be determined and allocated to interfaces and (2) including a provision ensuring that CBM, TRM and ETC cannot be used for the same purpose, such as the loss of an identical generation unit. Further, the Commission expressed concern that the Reliability Standard may unduly impact competition because of the lack of consistent criteria and clarity with regard to the entity on whose behalf CBM has been set aside.

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[174] The NERC glossary defines "capacity benefit margin" or "CBM" as the amount of firm transmission transfer capability preserved by a transmission provider for load serving entities whose loads are located on the transmission service provider's system, to enable access by the load serving entity to generation from interconnected systems to meet generation reliability requirements. NERC Glossary at 2.

This lack of consistent criteria has the potential to result in the transmission provider's setting aside capacity that it might not otherwise need to set aside, thus increasing costs for native load customers and blocking third party uses of the transmission system.

**i. Comments**

1070. APPA agrees with the Commission that MOD-004-0 should not be approved as a mandatory Reliability Standard until the relevant regional procedures are submitted and approved.[175]

1071. FirstEnergy states that transmission capacity margins such as CBM and TRM are vitally important to the reliability of the system, and any methodology that would unduly limit these margins could create a danger of limiting transmission capacity over interconnected facilities that would limit the ability of balancing authorities and others to obtain generation reserves needed from the grid during contingency events. In contrast, TAPS questions how TRM or, especially, CBM, can be viewed as Reliability Standards if they are optional for the transmission provider.

1072. MidAmerican supports greater uniformity of CBM definitions and calculations and states that the revised standard and/or new standards should support transparency and uniformity by encouraging increased availability of information and consistent data input and modeling assumptions. EEI emphasizes that additional data and information-sharing requirements would improve the transparency of various calculations and assumptions related to CBM, including this standard and the other CBM-related standards. EEI believes that, similar to the peer review processes of the planning studies carried out under the TPL standards, industry participants are best suited to developing the totality of assumptions, system conditions and other input variables that support the calculations.

1073. EEI notes that, with respect to the Commission's particular concern about criteria in determining resources and loads used in the CBM methodology, NERC's "ATC Definitions and Determination"[176] document clearly delineates the purpose and intent of the calculation of CBM and TRM. EEI states that CBM is intended to provide generation reliability, and TRM is intended to provide transmission reliability. EEI believes that, to

[175] APPA notes that it has expressed its own concerns with CBM calculations and set-asides in its August 7, 2006 Initial Comments filed in Docket No. RM05-25-000, at 31–55. APPA is hopeful these concerns can be addressed through NERC's Reliability Standards development process.

[176] NERC, Available Transfer Capability Definitions and Determination - A Framework for Determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market (June 1996).

the extent capacity capable of supplying CBM is located in the vicinity of the designated facility experiencing an outage, transmission may or may not be available under the native load reservation normally used for the facility. Therefore, EEI argues, CBM may be needed on an interface where capacity is available for use as CBM, and not allowing all generation to be considered in this manner may unduly increase the generation reserve requirement within the transmission provider's system.

1074. EEI agrees with the Commission's concern about double-counting TRM for those transmission providers who do not opt to use CBM. However, EEI argues that for transmission providers who do opt to use CBM, it may be appropriate in some circumstances to use the same generation unit outage to determine the impact on both generation and transmission reliability because the impacts are different. EEI cautions that artificially restricting such use is not appropriate, especially before NERC's development of TRM and CBM standards and their presentation to FERC through the Reliability Standards development process. EEI recommends that the Commission encourage transmission providers to make CBM and TRM capacity available to wholesale markets for purchase on a non-firm basis, because doing so would ensure that both CBM and TRM capacity are available to the transmission provider during system emergencies, as intended. EEI notes that at other times the transfer capability associated with TRM and CBM would be available to the market, alleviating the concern of possible double-counting. MidAmerican also supports the Commission's conclusion that double-counting would be inappropriate, although MidAmerican states that it is not aware of any cases of double-counting of margins.

1075. TAPS notes the significant potential for abuse[177] that could result from the current flexibility afforded transmission providers in the calculation of CBM and TRM, and proposes innovative approaches[178] to take CBM and (to the extent it is intended to cover transmission required for reserve sharing) TRM out of the hands of individual transmission providers, and to therefore reduce the opportunity for abuse.

**ii. Commission Determination**

1076. The Commission adopts the NOPR proposal not to approve or remand MOD-004-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-004-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest."

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[177] Documented by NERC's April 14, 2005 Long-Term AFC/ATC Task Force

Final Report.

[178] TAPS refers the Commission to its August 7, 2006 comments in Docket No.

RM05-25-000 at 21-24.

Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD-004-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO, through the Reliability Standards development process, to modify MOD-004-0 as discussed below.

1077. We agree with FirstEnergy that CBM is important for system reliability by allowing the LSEs to meet their historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. We agree with EEI and MidAmerican that transparency of the studies supporting CBM determination will reduce the opportunity for transmission service providers to overestimate the amount of CBM and misuse transfer capability. We therefore direct the ERO to develop Requirements regarding transparency of the generation planning studies used to determine CBM values. We also clarify that CBM should only be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. We expect verification of the CBM values to be part of the Requirements with appropriate Measures and Levels of Non-Compliance.

1078. We continue to believe this Reliability Standard should be modified to include a provision ensuring that CBM, TRM and ETC cannot be used for the same purpose, such as loss of the identical generating unit. In order to limit misuse of transfer capability set aside as CBM, we direct the ERO to provide more specific requirements for how CBM should be determined and allocated across transmission paths or flowgates. As we stated in Order No. 890, we do not mandate a particular methodology for allocating CBM to paths or flowgates. For example, one approach could be based on the location of the outside resources or spot market hubs that a LSE has historically relied on during emergencies resulting from an energy deficiency, but we agree with EEI that flexible rules should be allowed to prevent unnecessary increase of the generation reserve requirement within the transmission provider's system. Therefore, we support flexibility, but expect that the ERO, using its Reliability Standards development process, will adequately approach these complex technical issues and propose a new version of MOD-004-0 that addresses the methods for CBM determination and allocation on paths that will reduce reliability and discrimination concerns.

1079. In response to TAPS's question asking how CBM can be viewed as a Reliability Standard if it is optional to the transmission provider, our understanding is that transmission providers that have opted not to use CBM have instead set aside transmission margin (needed to bring in outside power to meet generation reliability criteria) either through ETC or TRM. CBM is not the only way to reserve transmission capacity for a margin. However, if the Reliability Standard is not clear regarding the method of calculating transmission margins, it may cause double-counting of transmission margins and reduction of ATC. As we stated in Order No. 890, we find that clear specification of the permitted purposes for which entities may reserve CBM and TRM will virtually eliminate double-counting of TRM and CBM. Therefore, we direct the ERO to modify its standard in order to prevent setting aside transfer capability for the same purposes.

1080. We share TAPS's concern that there is a significant potential for abuse as a result of the current flexibility afforded to transmission providers in the calculation of both CBM and TRM. In response to TAPS's concern, we clarify that in accordance with the OATT Reform Final Rule and the ERO CBM definition, each LSE has the right to request CBM be set aside and use it to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. As such, the LSEs that request CBM be set aside must be identified as applicable entities with identified Requirements, including Requirements on generation studies to verify the set aside, Measures and Levels of Non-Compliance. We direct the ERO to modify the Reliability Standard accordingly.

1081. We agree with TAPS that there is a need for clearer requirements in the standard regarding to whom and how to submit a request for CBM set-aside, and what the transmission service provider should do if the sum of all CBM requirements exceeds the amount of available transfer capability. We direct the ERO to address the reliability aspects in the Reliability Standards development process and explore with NAESB whether business practices would be required.

1082. Accordingly, the Commission neither accepts nor remands MOD-004-0 until the ERO submits additional information. In the interim, compliance with MOD-004-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD-004-0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those set forth in Order No. 890. Therefore, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process to: (1) clarify that CBM shall be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria; (2) develop requirements regarding transparency of the generation planning studies used to determine CBM value; (3) modify the current Requirements to make clear the process for how CBM is allocated across transmission paths or flowgates; (3) modify its standard in order to prevent setting aside CBM and TRM for the same purposes; (4) modify the standard by adding LSE as an applicable entity and (5) coordinate with NAESB business practice standards.

1083. We direct the ERO to consider APPA's suggestion that MOD-004-0 may be redundant and should be eliminated if the ERO develops a modification to the MOD-002-0 Reliability Standard that includes reporting requirements

### g. Procedure for Verifying Capacity Benefit Margin Values (MOD-005-1)

1084. MOD-005-1 specifies the requirements regarding the periodic review of a transmission service provider's adherence to the regional reliability organization's CBM methodology. It requires each regional reliability organization to: (1) develop and implement a procedure to review at least annually the CBM calculations and the resulting values determined by member transmission service providers; (2) document its CBM review procedure and (3) make the results of the most current CBM review available to NERC upon request.

1085. In the NOPR, the Commission identified MOD-005-0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and implement a procedure to review CBM calculations and the resulting values and to make the documentation of the results of the CBM review available to NERC and others. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD-005-0 until the ERO submits the additional information.

#### i. Comments

1086. APPA agrees that MOD-005-0 is a fill-in-the blank standard, and that in its current form, it is not sufficient and should not be accepted for approval as a mandatory Reliability Standard until the necessary regional procedures have been submitted and approved. APPA suggests that NERC modify MOD-006-0, so that MOD-004-0 and MOD-005-0 could be eliminated.

#### ii. Commission Determination

1087. The Commission adopts the NOPR proposal not to approve or remand MOD-005-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-005-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD-005-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

1088. As to APPA's comment on incorporating MOD-004 and MOD-005 into MOD-006, we direct the ERO to consider those comments through the Reliability Standards development process.

### h. Procedure for Use of Capacity Benefit Margin Values (MOD-006-0)

1089. The purpose of MOD-006-0 is to promote the consistent and uniform use of transmission CBM calculations among transmission system users. MOD-006-0 requires that each transmission service provider document its procedure for the scheduling of energy against a CBM reservation and make the procedure available on a website accessible by the regional reliability organization, NERC and transmission users.

1090. In the NOPR, the Commission proposed to approve Reliability Standard MOD-006-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-006-0 that: (1) includes a provision that will ensure that CBM and TRM are not used for the same purpose; (2) modifies Requirement R1.2 so that concurrent occurrence of generation deficiency and transmission constraints is not a required condition for CBM usage; (3) modifies Requirement R1.2 to define "generation deficiency" based on a specific energy emergency alert level and (4) expands the applicability section to include the entities that actually use CBM, such as LSEs.

1091. In addition, the Commission proposed that NERC should clarify the requirements to address when and how CBM can be used to reduce transmission provider discretion with regard to CBM usage. The Commission provided guidance expressing its belief that CBM should be used only when the LSE's local generation capacity is insufficient to meet balancing Reliability Standards, and that CBM should have a zero value in the calculation of non-firm ATC.

**i. Comments**

1092. APPA supports the Commission's proposal to approve MOD-006-0. Moreover, APPA agrees with the Commission's proposed directives[179] that the standard should address the use of CBM and TRM for the same purpose. However, APPA believes that the specificity of the Commission's proposed directives to NERC, if implemented, would undermine NERC's role as the approved ERO with the technical expertise to develop and revise standards for the Commission's subsequent review. APPA therefore suggests that the Commission in its Final Rule make clear to NERC its concerns about MOD-006-0, but then let NERC address those concerns through its Reliability Standard development process.

1093. Regarding the Commission's proposal that MOD-006-0 R1.2 be modified "so that concurrent occurrence of transmission constraints and a generation deficiency is not a requirement for CBM usage," WEPCO asserts that the Commission is misinterpreting CBM. WEPCO states that if there is no transmission constraint then there is no need to use CBM. In that case, transmission capacity exists for a LSE to import energy. If there is a transmission constraint, CBM reserves transmission capacity that the LSE can use to import energy for reliability needs.

[179] NOPR at P 642.

1094. EEI points out that the explicit intention for CBM is that it be used only during conditions where there are emergency generation deficiencies. However, EEI emphasizes that the Commission's recommendation does not consider that the LSE's supply and demand balance varies season to season, over time, and with supply and demand uncertainties. EEI says that the development of CBM quantities must be carried out in a manner that sets aside transmission capability for forecasted conditions and uncertainties much like the native load reservations necessary for serving reasonably forecasted native load. An argument may be made that during a period of time when a LSE's expected reserves are substantially greater than its targeted reserves, the need for CBM set-aside decreases. However, should the LSE foresee that this "excess" would occur substantially in the future, a reduction in CBM would not be warranted since substantial uncertainties still exist.

1095. Additionally, regarding the Commission's proposal that a LSE that "has sufficient generation resources within its balancing authority to meet the balancing Reliability Standards, should not need to preserve capacity for CBM at all," WEPCO argues that just because the balancing authority has sufficient generation does not mean that there is sufficient transmission capacity to deliver the energy to the LSE. WEPCO states that the LSE may be remote from the bulk of the balancing authority, so there may be occasions when a LSE that has sufficient generation resources within its balancing authority to meet the balancing Reliability Standards may still need to reserve capacity for CBM. In addition, EEI argues that the Commission's viewpoint does not take into account the availability of these resources unless they are under contract with the LSE to provide this service. EEI contends that the implication of this suggestion is to unduly restrict the sources of generation capacity available for CBM during times of generation shortage, which results in the LSE's being captive to local generation that is available and does not allow access to the market outside of the LSE's balancing authority. Additionally, EEI cautions that this action may require the LSE to develop contractual agreements with local generation and thus increase costs to the LSE's rate payers.

1096. Given the strong direction on CBM issues in the OATT Reform NOPR, TAPS assumes that the Commission would not be approving the Version 0 standards on these competitively crucial issues, but would continue to address them forcefully in the OATT Reform proceeding. TAPS notes that, although that is the course largely adopted by the NOPR in this proceeding, the NOPR[180] proposes to approve MOD-006-0 and MOD-007-0, with directions to improve these standards. TAPS notes that such action is inconsistent with the Commission's general approach to ATC/TTC/TRM/CBM standards in this docket and the OATT Reform NOPR. TAPS further states that, given the absence of clear access of non-transmission owner LSEs to CBM, the proposed expansion of MOD-007-0 to include such LSEs in the NOPR[181] seems bizarre.

[180] Id. at P 642, 648.

[181] Id. at P 647-48.

**ii. Commission Determination**

1097. The Commission adopts the NOPR proposal to approve MOD-006-0 as mandatory and enforceable. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO to modify MOD-006-0 as discussed below.

1098. Consistent with the views of many commenters, we adopt the NOPR proposal that requires a provision that will ensure that CBM and TRM are not used for the same purpose. As discussed under MOD-004-0 concerning the reservation of transfer capacity, we believe that if the Reliability Standard is not clear regarding the conditions specifying both the reservation and the use of CBM, it may cause double-counting. Such double-counting will lead to an unnecessary reduction of ATC, and create opportunities for discrimination. Therefore, we direct the ERO to modify its standard to prevent use of CBM and TRM for the same purposes. We agree with APPA that the ERO should use its Reliability Standards development process to address the double-counting problem.

1099. We adopt the NOPR's proposal and direct the ERO to modify Requirement R1.2 so that a transmission constraint is not a required condition for CBM usage. The glossary definition and the use as defined in Order No. 890 is that CBM "is intended to be used by the LSE only in time of emergency generation deficiencies."[182] Therefore we direct the ERO to modify the standard in the manner proposed in the NOPR.

1100. We adopt the NOPR proposal that requires modification of Requirement R1.2 to define "generation deficiency" based on a specific energy emergency alert level. This approach will provide clarity as to when the use of CBM may be permitted. We therefore direct the ERO to modify the Reliability Standard to include a specific energy emergency alert level that will trigger CBM usage.

1101. We also reiterate the direction in Order No. 890 that CBM should have a zero value in the calculation of non-firm ATC because non-firm service may be curtailed so that CBM can be used. CBM is reserved as part of the firm transfer capability so that it is available when needed for energy emergencies. We determine that each LSE should be permitted to call for use of CBM, provided all of the other Requirements of R1.1 are met. We direct that CBM may be implemented up to the reserved value when a LSE is facing firm load curtailments.

1102. We adopt the NOPR proposal that CBM should be used only when the LSE's local generation capacity is insufficient to meet balancing Reliability Standards, with the clarification that the local generation is that generation capacity that is either owned or contracted for by the LSE. We disagree with WEPCO that just because the balancing authority has sufficient generation does not mean that there is transmission capacity to

[182] See NERC Glossary at 2.

deliver the energy to the LSE. The Commission finds that such a scenario would violate existing transmission operating and transmission planning Reliability Standards. There is an explicit requirement in the transmission operating standards that generation reserves must be deliverable to load.[183] Also, there is an explicit requirement in the transmission planning standards that all firm load must be supplied under various system conditions with and without contingencies.[184] The Commission is not prescribing how these requirements should be met. There are a variety of approaches to do so, including adequate transmission capability, local or dynamic generation transfers into the area or DSM. To clarify for EEI, our proposal does not take into account the availability of these resources unless they are under contract with the LSE to provide this service. We developed our NOPR proposal on the rationale derived from the CBM concept, and believe that if there are enough resources to meet generation reliability criteria within the balancing authority, there is no need to request CBM.

1103. We also adopt the NOPR proposal to require the applicability section to include the entities that actually use CBM, such as LSEs. The current CBM definition in the NERC glossary determines that LSEs are users of CBM. Load-serving entities determine when to use CBM, initiate CBM use and call for its end. Load-serving entities therefore have to comply with the standard requirements that specify the conditions under which CBM will be used. We direct the ERO to modify the standard accordingly.

1104. With regard to TAPS's comments concerning its assumption that the Commission would not be approving the Version 0 standards on these issues, but would continue to address them in the OATT Reform proceeding, the Commission finds that MOD-006-0 and MOD-007-0 do not establish CBM values, but rather address CBM implementation and documentation. The implementation of CBM has critical implications for the reliable operation of the Bulk-Power System and we find that these Reliability Standards should be mandatory and enforceable. The competitively significant issue is to assure that there is no double-counting of CBM and to determine the magnitude of CBM which is addressed in other Reliability Standards that the Commission has not approved or remanded.

1105. The Commission approves MOD-006-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to Reliability Standard MOD-006-0 through the Reliability Standards development process that: (1) includes a provision that will ensure that CBM and TRM are not used for the same purpose; (2) provides that CBM should be used for emergency generation deficiencies; (3) modifies Requirement R1.2 to define "generation deficiency" based on a specific energy emergency alert level; (4) includes a provision that CBM should have a zero value

[183] TOP-002-2.

[184] TPL-002-0.

in the calculation of non-firm ATC and (5) expands the applicability section to include the entities that actually use CBM, such as LSEs.

### i. Documentation of the Use of Capacity Benefit Margin (MOD-007-0)

1106. MOD-007-0 requires transmission service providers that use CBM to report and post its use.

1107. In the NOPR, the Commission proposed to approve Reliability Standard MOD-007-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-007-0 that expands the applicability section to include the entities that actually use CBM, such as LSEs.

#### i. Comments

1108. APPA supports the Commission’s proposed approval of MOD-007-0. However, it believes that the issue of whether LSEs should be made subject to MOD-007-0 should be left to NERC in the first instance to decide. In so doing, NERC should consider expanding MOD-007-0 to cover not only LSEs, but also balancing authorities. Under NERC’s Functional Model, the balancing authority is the entity that would schedule energy over transmission capacity reserved as CBM. Moreover, it is the balancing authority that would know the information necessary to report an incident during which the balancing authority had to import energy from outside the balancing authority’s own area from a resource designated as operating reserves and change the net scheduled interchange with the neighboring balancing authorities to allow the energy to flow into the balancing authority’s area.

#### ii. Commission Determination

1109. The Commission approves MOD-007-0 as mandatory and enforceable. Consistent with the comments received in response to the NOPR, the Commission directs the ERO to modify the standard as discussed below.

1110. We also adopt the NOPR’s proposal to require the applicability section to include the entities that actually use CBM and report on their CBM use, such as LSEs. The current CBM definition in the NERC glossary determines when a LSE is a CBM user. The LSE determines how much CBM will be set aside, when CBM use will start and when it will end. The LSE must therefore comply with the standard requirements that require reporting and posting of CBM use. We direct the ERO to modify the standard to include the entities that actually use CBM, such as LSEs. In addition, we agree with APPA that the Reliability Standard should apply to balancing authorities and direct the ERO to include balancing authorities within the entities to which this standard is applicable.

1111. Accordingly, the Commission approves MOD-007-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification through its Reliability Standards development process that expands the applicability of MOD-007-0 to include the entities that actually use CBM, such as LSEs and balancing authorities.

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☒ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The Standard, as written, will continue to allow the applicable functions to define CBM without any amount of consistency, which is what Order 890 wanted the Standards to accomplish. In addition, the Standard does not recognize that ATC is calculated on 3 different time horizons and CBM transmission reservation will vary from the Monthly to the Daily to the Hourly calculations.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: All throughout this Standard the author has Reliability Functions performing duties that are counter to those duties prescribe in the Functional Model. In addition, the SDT has incorrectly included requirements for scheduling of energy, maintenance schedules, and so-on, which are preformed by other Reliability Functions in other Standards.

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The Standard has Functional Entities performing duties that is contrary to the Functional Model's directions. Examples are in Requirement R 1.3 and R 10; the scheduling of energy over the transmission capacity that is designated CBM only occur during the active hour to meet “generation reliability requirements.” The Balancing Authority is the only Function that has that authority to schedule energy during the real-time. This Standard, as written, will create an environment where confusion will exist during critical situation in the real-time and cause the possibility of a command and control break down during a critical situation in the real-time. To require the Transmission Service Provider or the Load Serving Entity to be responsible for declaring emergencies or scheduling energy during those emergencies will create very non-reliable situation. A large part of this Standard needs to be rewritten to ensure reliable operations.

5. In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The definition of CBM is causing the industry to calculate CBM is many different ways. The definition of CBM states that CBM is used to meet an entity's "generation reliability requirements." Some entities are saying that the use of CBM to handle "Planning Reserves" is the correct and reserve transmission capacity as CBM to bring in energy from energy resources outside the BA's area that were determined when the entity calculated "Planning Reserves." Other entities calculate the amount of CBM capacity based on "Operating Reserves." As the definition of CBM is written either one could be correct or incorrect. This definition worked well when the industry maintained reliability of the BES from Reliability Policies.

   The CBM definition's undefined term "generation reliability requirement" allows an excessive amount of transmission capacity to be removed from the BES as CBM and prevents the correct amount of ATC to be placed on the market for use by other entities. In addition, the definition of CBM is so general it is impossible for a Compliance Program to determine if an entity is non-compliant.

6. In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

   ☐ Yes

   ☒ No

   Comments: The needs to secure a transmission path to reach generation resources outside a LSE Balancing Authority Area that will "meet generation reliability requirements" are extremely important to reliable operations of the BES. Since the Reliability Standards are written to insure reliable operations a TSP would be hard pressed to deny an LSE the ability to secure resources to meet "generation reliability requirements." If a TSP denied this service it could be exposed to acts of non-compliance should the BES's integrity diminish because the TSP denied the LSE the CBM capacity.

7. Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

   ☐ Yes

   ☒ No

   Comments: The use of CBM capacity is just a reservation of transmission capacity that will only be used should an adverse situation develop in the BES and generation resources are needed to meet "generation reliability requirements." However, those generation resources are out side the LSE's Balancing Authority's Area. The simulation of energy over the CBM would be a study to determine how the system reacted under adverse operating conditions of the BES. How the use of CBM transmission capacity is treated will be determined how the final definition of CBM is written. Presently, both method would be needed because CBM is used for different purposes throughout the industry.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: Reducing the CBM because new generation is built in the LSE's Balancing Authority's Area would be a financial decision by the LSE. I do not believe this Standard has authority to mandate financial decisions. However if new reliability rules are passed that limit the amount of resources located outside the LSE's Balancing Authority's Area, which can be used to meet "generation reliability requirements" then this Standard has the obligation to lower the CBM to the predetermined about of transmission capacity used for CBM.

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: The LSE is performing many functions of the other Functional Entities, which are described in the Functional Model. As stated in Question 3 the author has incorrectly assigned duties of many different Functional Entities to the LSE in R.6 and will create confusion between this Standard and other Standards that are written for the many different subjects covered in R.6. It is recommended this requirement be completely removed.

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: As noted above.

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: NA

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: It is not within the scope of this SDT to deal with resource studies, in fact the glossary states the Resource Planner determines the resource adequacy. Generation Reserves has not been defined in the standards nor has Resource Adequacy.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: It is not within the scope of this SDT to deal with resource studies, in fact the glossary states the Resource Planner determines the resource adequacy. LOLE and LOLP are methods used by the Resource Planners.

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☒ | 5 — Electric Generators |
| ☐ **SERC** | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: R1 of MOD-004-1 needs to clarify that CBM procedures need only be made publicly available if the Transmission Service Provider uses CBM.

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments: The discussion of CBM in Order 890 and NERC's definition of CBM refer only to generation reliability requirements, not resource adequacy requirements. Please clarify what is meant by "resource adequacy requirements".

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☐ No

Comments:

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: R1. through R9. and R13. should be clarified that CBM need only be posted and requested on Posted Paths, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: For Generation Reserve and Resource Adequacy requirements, BPA follows the procedures developed by the Northwest Power Pool which meet the WECC's Minimum Operating Reliability Criteria. BPA also meets the requirements in the NERC standards for Control Performance BAL-001-0 and Disturbance Control BAL-002-0.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply:

**WECC MIC MIS ATC Task Force / Attendance Sheet**
**Attendance for WECC-Specific NERC Comments**

| NAME | Company | PHONE | E-MAIL | Present |
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| Brian Jobson | SMUD | 916-732-5939 | bjobson@smud.org | |
| Brian Weber | Pacifcorp | (503) 813-6444 | Brian.weber@pacificorp.com | |
| Casey Sprouse | Sr. Term Marketer | (509) 989-2081 | www.csprous@gcpud.org | |
| Charles Mee | Ca. DWP | (916) 574-0669 | cmee@water.ca.gov | |
| Chuck Falls | SRP | (602) 236-0965 | Chuck.Falls@srpnet.com | |
| Dave Lunceford | CAISO | (916) 351-2292 | dlunceford@caiso.com | |
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| Maria Denton | SRP | 602-236-4328 | Maria.Denton@srpnet.com | |
| Mike Wells | WECC | 801-582-0353 | mike@wecc.biz | |
| Patricia vanMidde | FERC Case MRG, Sempra | (858) 654-1716 | pvanmidde@SempraUtilities.com | |
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| Sueyen McMahon | LADWP | (818) 771-778 | Sueyen.McMahon@ladwp.com | |
| Terri M. Kuehneman | SRP System Operation | (602) 236-4392 | tmkuehne@srpnet.com | |
| Steve Tran | BP TX | | | |

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team’s decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If “No,” please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission’s (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC’s directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If “No,” please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the “Applicability” section of the draft standard? If “No,” please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If “No,” please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☒ Yes

☐ No

Comments: CBM requests should be addressed on a "first-come first-served" basis. LSE's are required to submit annual 10-year projections to the Transmission Service Provider. CBM requests will have lower priority than existing queued firm transmission service requests. NAESB should formalize the queuing process.

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: The standard should be flexible enough to allow the Transmission Service Provider to use either method which best supports reliability in their control area.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: As resource mix changes, CBM would be re-evaluated on an annual basis with updated LSE requests for CBM.

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: R3.1.1 - Existing Transmission Commitments (ETC) is not included in definitions, but it should be defined.

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: The NC and SC state commissions exercise their authority in this area by requiring an annual filing by the regulated utilities, which includes the identification and justification of reserve margins.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: None

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| ☐ **RFC** | ☐ | 5 — Electric Generators |
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| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| George Bartlett | Entergy Services Inc. | **SERC** | Transmission Owner |
| Jim Case | Entergy Services Inc. | **SERC** | Transmission Owner |
| Ed Davis | Entergy Services Inc. | **SERC** | Transmission Owner |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments: Entergy supports combination of CBM Calculation, verification, preservation, and use into one standard.

**2.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**3.** The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

☒ Yes

☐ No

Comments:

**4.** The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☒ No

Comments: There is no need to have a queue process for CBM. Transmission Service Requests are approved if ATC is available and ATC is calculated using CBM. Therefore, CBM needs to be set aside first to accurately calculate ATC before Transmission Service Requests can be approved.

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: CBM should be set aside on a path based on the response of CBM import MW level on that path. This should be treated similar to impact of loads or generation on paths by including their response on paths rather than algebraically subtracting from the path..

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: CBM should be recalculated to determine accurate CBM requirements that should include meeting the generation requirement from any other transmission service or new generation. Any double counting of elements that impact CBM calculations should be avoided.

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: Requirement R6 addresses resource adequacy requirement and it does not belong in the CBM standard. Requirement R5.2 covers identification of appropriate criteria used for resource adequacy studies that will identify need for CBM, if any. Probabilistic studies, if included in resource adequacy studies criteria shall be used and there is no need to include requirement R6 in this standard.

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: Entergy does not understand asking for comments on standard MOD-001-1 in this questionaire. Requirement R8.1 should include a condition by appending the language " if other entities who reserved CBM on that path are not using their share of CBM. Under no circumstances, the total use of CBM by all entities on a path at any time will exceed the total amount of CBM reserved on that path and for that period." Definitions of terms on page 2 do not belong in this standard and should be removed. Entergy does not use CBM in their ATC/AFC calculations. It appears from the standard that it is mandatory for Transmission Service Providers to use CBM. It should be left to the descretion of Tansmission Service Provider to use CBM and its use should not be made mandatory.

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply:

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply:

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Steve Myers | |
| Organization: | ERCOT | |
| Telephone: | 512-248-3077 | |
| E-mail: | smyers@ercot.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☒ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: See IRC comments submitted by Charles Yeung.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: See IRC comments submitted by Charles Yeung.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: See IRC comments submitted by Charles Yeung.

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☒ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area Interconnection and there has been no reservation of transmission capacity in ERCOT.

Capacity Benefit Margin is defined as the amount of firm transmission transfer capability preserved by the transmission provider for Load- Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. In the current and future ERCOT market design the use of CBM is not applicable to the ERCOT Interconnection. ERCOT does not have a synchronous connection with any other Control Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance.

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: See IRC comments submitted by Charles Yeung.

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?

Reply: Within ERCOT, a technical recommendation is developed by ERCOT System Planning, acting as the Planning Coordinator. ERCOT Market Participants can give input to the process through open meetings. The technical recommendation is subject to approval by the ERCOT Board of Directors and the Public Utilities Commission of Texas (PUCT). The technical recommendation stipuates generation reserve and resource adequacy requirements both for long term planning and for operating reserve.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: CBM is not used within ERCOT.

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Dave Folk | | |
| Organization: FirstEnergy Corp. | | |
| Telephone: 330-384-4668 | | |
| E-mail: folkd@firstenergycorp.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
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| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Richard Kovacs | FirstEnergy Corp. EDPP | | |
| Phil Bowers | FirstEnergy Corp. EDPP | | |
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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☒ No

Comments: CBM is a reliability product that must be available when called upon. Transmission service requests are a business product that may have reliability impacts if properly scheduled. Any queing process would have to give priority to CBM.

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: The posted ATC for the CBM reserved path should have been based on the network response or contractual limit for that POR to POD, and thus subtracting CBM on that path is consistent with the ATC determination.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: In the case of new generation, the recalcuation periodicity would conceivably be in frequent. In the case of capacity-backed transmission service, the recalculation periodicity may be frequent, but is necessary to allow the markets to function properly.

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: R2 requires copies of models used for CBM allocation, but the allocations are not required to be and may not be based on power flow modeling. In addition, it requires a request from an entity with a valid need. Methods are needed to determine what constitutes a valid need, who decides the validity of the need, and for resolving disputes. R4.2 requires the LSE to allocate the CBM by path; however, the LSE may not have/use power flow tools consequently they may have difficulty complying with this requirement. The standard should include a method for managing offsetting resource requirements where the TSP has multiple LSEs such as the situation where LSE A provides needed energy to LSE B without requiring an import. Under this scenario too much CBM may be set aside as the standard is currently written. R7.1 appears to attempt to cover this situation but it is not clearly stated and the basis for managing this is not addressed. R13 states the TP "shall include all valid requests and projected CBM import MW requirements ... in its planning process." However, a method for needs to be established for managing situations where the import limitation is outside his area of responsibility. Overall, there are many good things in here. R12 requires the TSP to make publicly available the report prepared by the LSE pursuant to R11. This requirement should be placed on the LSE that created and owns the report and has the retention responsibility. To reduce confusion R14 should list the components of uncertainty rather than refering to MOD-008-1 R1.1. This MOD-008-1 requirment requires TPs and TOPs to include these elements in the TRM analysis where MOD-004-1 requires the LSE to exclude these values from the CBM calculation. The difference in application may be lost in switching back and forth between the two standard's requirements.

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: The Regional Reliability Organization - ReliabilityFirst

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.

- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: Currently the ISO determines CBM via an LOLE study based on 1/10 of a day/year. Currently Ohio does not have a requirement for an LOLP. ReliabilityFirst has established a 1 day in 10 year LOLP criteria that is voluntary. In the future, the ISO PRSG may self-contract an LOLP enforcement requirement. It is expected that the ISO market rules will eventually enforce LOLP.

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Ron Falsetti | | |
| Organization: IESO | | |
| Telephone: 905-855-6187 | | |
| E-mail: ron.falsetti@ieso.ca | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☒ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: We do not agree with combining all of the above mentioned standards in one standard (MOD-004). This coupled with the need to make a distinction between the ATC calculation methods used and the descriptive procedure for resource adequacy assessment has made the new MOD-004 very convoluted, and the requirements difficult to follow and measured. If combining some standards of related objective is desired, a more manageable and appropriate alternative is to divide these 4 standards into two groups - one on the determining and verifying the calculation of CBM and the other on the use and reporting of use of CBM.

**2.** The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments: In a general sense, yes, but the amount of detail seems to exceed the requirements implied by the FERC directives, which has resulted in repetitions and circular requirements. For example, R5 repeats most of R4's requirements, except in R5 the retention periods are specified, which arguably should be covered in the compliance section. Another example is R6.1 suggests that the CBM is calculated as a parameter or a by-product of a resource adequacy assessment, but R6.2 requires that the load assumption of the CBM study be the same as that assumed in the the resource adequacy assessment.

**3.** The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

☐ Yes

☒ No

Comments: There is only one requirement for the Transmission Planner, and that is in R13. However, we do not feel that R13 belongs to this standard. The inclusion of requested and projected CBM values in its planning process belongs to a standard that stipulate requirements for transmission planning. If this requirement is removed or relocated, then TP does not need to be included as an applicable entity. Similar thoughts for the applicability of the BA.

**4.** The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: Please see the above comments on some of the repetitive and extraneous requirements.

**5.** In the NERC glossary, CBM is defined as being necessary to meet “Generation Reliability Requirements.” Do you believe the current NERC definition is adequate? If “No,” please explain why in the comments area.

☐ Yes

☒ No

Comments: We should redefine it along the line that is provided in FERC's directive that CBM is required for generation deficiency only.

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If “Yes” please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☒ No

Comments: By virtue of the definition and formula of ATC determination, CBM is the component that must be allotted before any transmission service requests are assessed and granted.

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments: The way it is specified in R3.3 (and R3.2) is the correct approach.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: CBM is intended for having transmission capability to meet generation deficiency. If this deficiency can be met via other means, then the CBM allotted will no longer be required and could even be reduced to 0 if required.

**9.** Do you think that Requirement R6 is appropriate for this standard? If “No,” please explain why in the comments area.

☒ Yes

☒ No

Comments: By and large, R6 describe the process and assumption requirements for resource adequacy assessment via which the CBM is determined. It is our interpretation that FERC requires the basis of this assessment be made known to support and demonstrate a fair and consistent approach is taken in determining the CBM value. That said, R6 could arguably be placed in a standard on resource adequacy assessment. If R6 is to stay, at the very least some of the subrequirements can be removed or combined (see Comments under Q2 for an example).

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: However, there are entities that do not provide physical transmission services. Hence, these standards or some of the requirements in these standards may not apply.

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: ETC is introduced in this standard for the first time and hence this term needs to be defined here.

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: In Ontario, it would be the IESO and the Ontario Power Authority (OPA) which would be responsible for establishing generation reserve and resource adequacy requirements.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: The IESO uses stochastic tools like GE MARS to establish reserve requirements for meeting loss of load expectations (LOLE). However, for Ontario, the concept of CBM is not used and is set to 0.

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

| | |
|---|---|
| Group Comments (Complete this page if comments are from a group.) | |
| **Group Name:** | IRC Standards Review Committee |
| **Lead Contact:** | **Charles Yeung** |
| **Contact Organization:** | **SPP** |
| **Contact Segment:** | **2** |
| **Contact Telephone:** | **832-724-6142** |
| **Contact E-mail:** | **cyeung@spp.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Jim Castle | NYISO | **NPCC** | 2 |
| Alicia Daugherty | PJM | **RFC** | 2 |
| Ron Falsetti | IESO | **NPCC** | 2 |
| Matt Goldberg | ISO-NE | **NPCC** | 2 |
| Brent Kingsford | CAISO | **WECC** | 2 |
| Steve Myers | ERCOT | **ERCOT** | 2 |
| Anita Lee | AESO | **WECC** | 2 |
| Bill Phillips | MISO | **RFC+** | 2 |
| | | **MRO+** | |
| | | **SERC+** | |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin.  Once there is consensus on the requirements, the drafting team will add measures and compliance elements.  Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages.  Comments must be submitted by **June 24, 2007**.  You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: We do not agree with combining all of the above mentioned standards in one standard (MOD-004). This, coupled with the need to make a distinction between the ATC calcualtion methods used and the descriptive procedure for resource adequacy assessment has made the new MOD-004 very convoluted, and the requirements difficult to follow and measured. If combining some standards of related objective is desired, a more manageable and appropriate alternative is to divide these 4 standards into two groups - one on the determining and verifying the calculation of CBM and the other on the use and reporting of use of CBM.

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: In a general sense, yes, but the amount of detail seems to exceed the requirements implied by the FERC directives which has resulted in repetitions and circular requirements. For example, R5 repeats most of R4's requirements, except in R5 the retention periods are specified, which arguably should be covered in the compliance section. Another example is R6.1 suggests that the CBM is calculated as a parameter or a by-prodcut of a resource adequacy assessment, but R6.2 requires that the load assumption of the CBM study be the same as that assumed in the the resource adequacy assessent.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: There is only one requirement for the Transmission Planner, and that is in R13. However, we do not feel that R13 belongs to this standard. The inclusion of requested and projected CBM values in its planning process belongs to a standard that stipulate requirements for transmission planning. If this requirement is removed or relocated, then TP does not need to be included as an applicable entity. Similar thoughts for the BA.

**4.** The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: Please see the above comments on some of the repetitive and extraneous requirements.

5. In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: We should redefine it along the line that is provided in FERC's directive that CBM is required for generation deficiency only.

6. In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☒ No

Comments: By virtue of the definition and formula of ATC determination, CBM is the component that must be allotted before any transmission service requests are assessed and granted.

7. Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: CBM on path/flowgate should be the 'max' rather than 'sum' of all that's required to meet each individual LSE's resource adequacy requirement. Reasoning: Generation emergencies don't happen all at once. Reserve a 'sum' is beyond the 1-day-in-10-year criterion (or whatever criterion that's used by the region), and is not an efficient way of utilizing transmission capacity..

8. If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: CBM is intended for having transmission capability to meet generation deficiency. If this deficiency can be met via other means, then the CBM allotted will no longer be required.

9. Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☒ Yes

☒ No

Comments: By and large, R6 describe the process and assumption requirements for resource adequacy assessment via which the CBM is determined. It is our interpretation that FERC requires the basis of this assessment be made known to support and demonstrate a fair and consistent approach is taken in determining the CBM value. That said, R6 could arguably be placed in a standard on resource adequacy assessment. If R6 is to stay, at the very least some of the subrequirements can be removed or combined (see Comments under Q2 for an example).

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: However, there are entities that do not provide physical transmission services. Hence, these standards or some of the requirements in these stnadards may not apply.

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: ETC is introduced in this standard for the first time. This needs to be defined here.

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: Unable to provide a specific answer as a group. Gernally speaking, however, it is the region that stipuates generation reserve and resource adequacy requirements both for long term planning as well as for operating reserve. (SRC please note: I'm only speculating. Don't let me put words in your mouth)

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
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- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: Unable to provide a specific answer as a group. Again, the LOLE approach is rather commonly used by the ISOs and RTOs in assessing resource adequacy. (SRC please note: ditto the above)

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| **Individual Commenter Information** | | |
|---|---|---|
| **(Complete this page for comments from one organization or individual.)** | | |
| Name: | Brian Thumm | |
| Organization: | ITC | |
| Telephone: | 248-374-7846 | |
| E-mail: | bthumm@itctransco.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: We highly recommend sticking to one single standard to address all of the CBM requirements.

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: The NERC glossary and CBM definition should be expanded to include other terms, such as "Resource Adequacy" to fully address this issue. This expansion may come as a result of future LSE requests for CBM based on a justification not currently envisioned.

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☒ No

Comments: Absolutely not. The original justification for CBM is that the transmission system was built for the contingencies envisioned by CBM. It was paid for by the original local network customers. No one should be allowed, by queuing process, to supercede this. However, if there is not sufficient transmission capacity to provide a CBM margin as well as requests for transmission service, the system should be expanded to provide the needed capacity. While there is a system impact process to cover this situation, it has not worked well in the last 10 years. Improved import capacity into a deficient system to meet all needs should be addressed in the planning process not some queuing process.

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: It should be based on the response of the network to the most likely sources. It is important that the availability of generation in the source area be considered when doing this. For example, assuming a source network with minimal reserves would be a poor assumption. This is an area that will ultimately require a very astute compliance monitor to determine compliance.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: This is a simple answer. You invite double counting if you don't reduce CBM when this happens. It amounts to hoarding. This is already a problem in our opinion.

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☒ Yes

☒ No

Comments: How else would a compliance monitor be able to evaluate a justification for CBM if he doesn't have the input used to make such a determination. If anything, this could be expanded to assist the compliance monitor in such a determination.

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: R4 gives the LSE great latitude in defining their resource adequacy requirements. R4 allows the LSE to fully document whatever requirement they have. It will ultimately be up to the compliance monitor to evaluated their justification and documentation.

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: (note question 11 should have referred to MOD-004 not MOD-001) While compliance has not been addressed, it is worth noting that the compliance monitor for CBM requirements will have to be a very astute individual or group to deal with the multiple possible resource adequacy requirements under the ERO. They will no doubt have to deal with non-jurisdictional entities to make their evaluations. We suspect it will be a lengthy process in some cases. We would also like to point out that the TSP has little latitude in using the MW import requirement supplied by the LSE. If they suspect that this value is too high, they don't have recourse here to do anything about it. Even if a large fine could result from a compliance issue, the TSP must sell service with a margin they may have good reason to feel is unjustified. Is a large find justification enough to not give the TSP some latitute?

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: ITC does not have a resource adequacy requirement. We must work with the LSEs in our service territory to determine appropriate CBM to plan for. These requirements allow for this to happen.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: ITC does not have a requirement, although we are familiar with the LOLE/LOLP evaluations. We strongly believe that R6 is a must for this standard. We have heard estimates that as much as 90% of the load in this country is subject to LOLE requirements based on LOLP studies. To not have requirements in this area would be negligent.

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
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| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: R8.1 needs clarification.

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☐ No

Comments:

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: The use of CBM capacity is for LSE under any potential emergency of generation deficiency. By modeling the CBM as the transaction from the POR to POD at the required CBM import MW level would treat the adverse operation asa normal condition and reduce the import TTC for the TSP.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments:

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments:

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply:

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply:

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| Individual Commenter Information (Complete this page for comments from one organization or individual.) | | |
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| E-mail: tcmielnik@midamerican.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: 1. R3.1.2, R3.2.1, and R3.3.1 should be clarified by matching the language in FERC 890 as follows: "The Transmission Service Provider shall not include transmission capacity set aside for THE INCREMENTAL POWER FLOWS RESULTING FROM reserve sharing in CBM." (The words in all caps be added.) It could be that CBM is reserved to the LSE's generation reliability criteria which is based upon a reserve sharing requirement. It is just that those flows that result from increment power flows resulting from reserve sharing are to be included in TRM. 2. In R1.1, it would be better to include the exact language from Order 890 in the parantheses to explain the resource adequacy requirements that are to be included in the CBM, as follows: "…..for meeting its resource adequacy requirement (i.e., its procedure for setting aside of Transfer Capability in the form of CBM to MEET a Load-Serving Entity's GENERATION RELIABILITY CRITERIA.)

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: I believe that the Functional Entity as provided in A.4.1.1 should not be qualified, for example, A.4.1.1 should just list Load-Serving Entity. However, if the Standards Drafting Team continues to list only those "Load-Serving Entity that is entitled and would like to have transmission capability set aside in the form of CBM" then I recommend that "would like" changed to "needed" in other words, reservation of CBM should not be based on likes but based on needs as demonstrated with the studies to be provided in support of the CBM.

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: 1. I recommend that R2 be changed from "following a request by an entity with a valid need for such information" to "following a request by a Functional Entity with a valid need for such information, subject to security and confidentiality requirements." 2. R5.3 does not represent all the conditions that organizationally exist, therefore, I recommend that a bullet be added under R5.3 as follows" "Planning Reserve Sharing Group reserve margin to meet the Regional Reliability Organization resource adequacy requirements". 3. R6.2 should refer to "a load forecast that has a 50/50% probability of occurrence". This means that there is a 50% probability that the load will actually be below the forecast and there is a 50% probability that the load is above the forecast. A statement that it is a 50% probability forecast has no mening without adding some information to it. For example, is it a 50% Confidence Interval forecast in which case it would be two numbers with 50 percent probability that the actual number will be within the two numbers.

5. In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☒ Yes

☒ No

Comments: It would be better if CBM is defined in the NERC glossary as provided in the FERC Order 890 as meeting "Generation Reliability Criteria" however, the existing definition is adequate.

6. In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☒ No

Comments: CBM is basic reliability requirement. If not met, transmission expansion planning should plan for it and should not sell addition transmission service on the same path/flowgate.

7. Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: CBM on path/flowgate should be the 'max' rather than 'sum' of all that's required to meet each individual LSE's resource adequacy requirement. Reasoning: Generation emergencies don't happen all at once. Reserve a 'sum' is beyond the 1-day-in-10-year criterion (or whatever criterion that's used by the region), and is not an efficient way of utilizing transmission capacity.

8. If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: It is to the benefits of all stakeholders if the use of transmission is optimized so CBM should be re-evaluated and possible reduced if CBM is met by other means.

9. Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☒ Yes

☒ No

Comments: I prefer if all CBM requests were supported by appropriate probabilistic based studies. It does seem odd that when the better approach (the probabilistic approach) is used, then the standard has all kinds of requirements defining how the better approach is to be done.

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: The purpose of each of the standards should be revised to be more in-line with the other ATC/TTC/TRM stanadards. The purpose in this standard be revised to state: "To promote the consistent and transparent…use of Capacity Benefit Margin (CBM) for reliable system operation."

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: It is my understanding of the 2005 Energy Policy Act that the Regional Reliability Organization or NERC can either set the generation reliability critiera or enforce the generation reliability criteria, but it cannot do both. The MRO is in the process of proposing to set the generation reliability criteria as 1 day in 10 years. It will be the responsibility of the Load Serving Enetity or its delegate (such as a Planning Reserve Sharing Group) within the MRO to set the reserve margin to meet the 1 day in 10 year criteria. The State will enforce the generation reliability criteria and the Planning Reserve Sharing Group will enforce the reserve margin requirement.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: I would prefer an LOLE study requirement to support the CBM requests of the Load Serving Entities.

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

### Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: 1. R3.1.2, R3.2.1, and R3.3.1 should be clarified by matching the language in FERC 890 as follows: "The Transmission Service Provider shall not include transmission capacity set aside for THE INCREMENTAL POWER FLOWS RESULTING FROM reserve sharing in CBM." It could be that CBM is reserved to the LSE's generation reliability criteria which is based upon a reserve sharing requirement. It is just that those flows that result from increment power flows resulting from reserve sharing are to be included in TRM. 2. In R1.1, it would be better to include the exact language from Order 890 in the parantheses to explain the resource adequacy requirements that are to be included in the CBM, as follows: ".....for meeting its resource adequacy requirement (i.e., its procedure for setting aside of Transfer Capability in the form of CBM to MEET a Load-Serving Entity's GENERATION RELIABILITY CRITERIA.) 890 and 693 also require some level of consistency and the methodology requirements for CBM appear to be fill-in-the-blank.

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: Many of the requirements are fill-in-the-blank (Isn't R1.2 a requirement to "tell me how you do it? and shouldn't it be "this is how you do it")

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☒ Yes

☐ No

Comments: This should be address in the TSPs OATT and filed at FERC. (Maybe it could be a requirement to just that in this standard)

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments: (Not sure if the Yes/No is for the first part of thequestion or the second) Network Response on path should be based upon network response by modeling it from the POR to the POD.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: It is to the benefits of all stakeholders if the use of transmission is optimized so CBM should be re-evaluated and possible reduced if CBM is met by other means. Maybe the TSPs OATT should be the right place for this information.

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: FERC Order 890 required consistency and this standard does not require any consistency.

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: The purpose of each of the standards should be revised to be more in-line with the other ATC/TTC/TRM stanadards. We recommend that the purpose in this standard be revised to state: "To promote the consistent and transparent…use of Capacity Benefit Margin (CBM) for reliable system operation." The standard should make it clear that an LSE should be required to do comply with certain requirements within this standard only if it requests CBM. Also this industry is sophisticated enough to perform or have performed a probabilistic study so that it what the CBM should be based on.

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply:

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: LOLE study

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Michelle Rheault | |
| Organization: | Manitoba Hydro | |
| Telephone: | 204-487-5445 | |
| E-mail: | mdrheault@hydro.mb.ca | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☒ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

**5.** In the NERC glossary, CBM is defined as being necessary to meet “Generation Reliability Requirements.” Do you believe the current NERC definition is adequate? If “No,” please explain why in the comments area.

☐ Yes

☐ No

Comments:

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If “Yes” please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☐ No

Comments:

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Do you think that Requirement R6 is appropriate for this standard? If “No,” please explain why in the comments area.

☐ Yes

☐ No

Comments:

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: MH is not a supporter of the use of CBM as we believe that CBM makes the unsupportable assumption that there will be energy and transmission avaialable in the adjoining entitity during the time of the emergency. However as there a desire to maintain this feature, MH believes that there should be a requirement to build if CBM causes the AFC on a flowgate to become negative and that a portion of cost should be assigned to the LSE who is responsible for the CBM.

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

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- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply:

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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| ☐ **RFC** | ☐ | 5 — Electric Generators |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** Midwest Reliability Organization (MRO)

**Lead Contact:** **Tom Mielnik**

**Contact Organization:** **MRO for Group (MEC for lead contact)**

**Contact Segment:** **10**

**Contact Telephone:** **563-333-8129**

**Contact E-mail:** **tcmielnik@midamerican.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Neal Balu | WPS | **MRO** | 10 |
| Terry Bilke | MISO | **MRO** | 10 |
| Robert Coish, Chair | MHEB | **MRO** | 10 |
| Carol Gerou | MP | **MRO** | 10 |
| Ken Goldsmith | ALT | **MRO** | 10 |
| Todd Gosnell | OPPD | **MRO** | 10 |
| Jim Haigh | WAPA | **MRO** | 10 |
| Joe Knight | GRE | **MRO** | 10 |
| Pam Oreschnick | XEL | **MRO** | 10 |
| Dave Rudolph | BEPC | **MRO** | 10 |
| Eric Ruskamp | LES | **MRO** | 10 |
| Mike Brytowski, Secretary | MRO | **MRO** | 10 |
| 28 Additional MRO Members | MRO | **MRO** | 10 |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: 1. R3.1.2, R3.2.1, and R3.3.1 should be clarified by matching the language in FERC 890 as follows: "The Transmission Service Provider shall not include transmission capacity set aside for THE INCREMENTAL POWER FLOWS RESULTING FROM reserve sharing in CBM." (The MRO is recommending that the words in all caps be added.) It could be that CBM is reserved to the LSE's generation reliability criteria which is based upon a reserve sharing requirement. It is just that those flows that result from increment power flows resulting from reserve sharing are to be included in TRM. 2. In R1.1, it would be better to include the exact language from Order 890 in the parantheses to explain the resource adequacy requirements that are to be included in the CBM, as follows: ".....for meeting its resource adequacy requirement (i.e., its procedure for setting aside of Transfer Capability in the form of CBM to MEET a Load-Serving Entity's GENERATION RELIABILITY CRITERIA.)

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☒ No

   Comments: The MRO believes that the Functional Entity as provided in A.4.1.1 should not be qualified, for example, the MRO recommends that A.4.1.1 just list Load-Serving Entity. However, if the Standards Drafting Team continues to list only those "Load-Serving Entity that is entitled and would like to have transmission capability set aside in the form of CBM" then the MRO recommends that "would like" changed to "needed" in other words, reservation of CBM should not be based on likes but based on needs as demonstrated with the studies to be provided in support of the CBM.

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: 1. MRO recommends that R2 be changed from "following a request by an entity with a valid need for such information" to "following a request by a Functional Entity with a valid need for such information, subject to security and confidentiality requirements." 2. R5.3 does not represent all the conditions that organizationally exist in the MRO, therefore, we recommend that a bullet be added under R5.3 as follows" "Planning Reserve Sharing Group reserve margin to meet the Regional Reliability Organization resource adequacy requirements". 3. R6.2 should refer to "a load forecast that has a 50/50% probability of occurrence". This means that there is a 50% probability that the load will actually be below the forecast and there is a 50% probability that the load is above the forecast. A statement that it is a 50% probability forecast has no mening without adding some information to it. For example, is it a 50% Confidence Interval forecast in which case it would be two numbers with 50 percent probability that the actual number will be within the two numbers.

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☒ Yes

☒ No

Comments: It would be better if CBM is defined in the NERC glossary as provided in the FERC Order 890 as meeting "Generation Reliability Criteria" however, the existing definition is adequate.

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☒ No

Comments: CBM is basic reliability requirement. If not met, transmission expansion planning should plan for it and should not sell addition transmission service on the same path/flowgate.

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: CBM on path/flowgate should be the 'max' rather than 'sum' of all that's required to meet each individual LSE's resource adequacy requirement. Reasoning: Generation emergencies don't happen all at once. Reserve a 'sum' is beyond the 1-day-in-10-year criterion (or whatever criterion that's used by the region), and is not an efficient way of utilizing transmission capacity.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: It is to the benefits of all stakeholders if the use of transmission is optimized so CBM should be re-evaluated and possible reduced if CBM is met by other means.

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☒ Yes

☒ No

Comments: The MRO would prefer if all CBM requests were supported by appropriate probabilistic based studies. It does seem odd that when the better approach (the probabilistic approach) is used, then the standard has all kinds of requirements defining how the better approach is to be done.

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: The purpose of each of the standards should be revised to be more in-line with the other ATC/TTC/TRM stanadards. The MRO recommends that the purpose in this standard be revised to state: "To promote the consistent and transparent…use of Capacity Benefit Margin (CBM) for reliable system operation."

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: It is the MRO's understanding of the 2005 Energy Policy Act that the Regional Reliability Organization or NERC can either set the generation reliability critiera or enforce the generation reliability criteria, but it cannot do both. The MRO is in the process of proposing to set the generation reliability criteria as 1 day in 10 years. It will be the responsibility of the Load Serving Enetity or its delegate (such as a Planning Reserve Sharing Group) within the MRO to set the reserve margin to meet the 1 day in 10 year criteria. The State will enforce the generation reliability criteria and the Planning Reserve Sharing Group will enforce the reserve margin requirement.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: MRO would prefer an LOLE study requirement to support the CBM requests of the Load Serving Entities.

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Robert W. Creighton | |
| Organization: | Nova Scotia Power, Inc. | |
| Telephone: | 902-428-7775 | |
| E-mail: | robert.creighton@nspower.ca | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: What happened to the requirement that CBM is a planning quantity only and tends to zero in the operating horizon. Does this mean that CBM cannot be used for non-firm import transactions?

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☐ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

5. In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: CBM is required to meet Resource Adequacy Requirements. Generation Reliability implies that access to transmission makes generation (and generators) more reliable. Resource Adequacy ensures that firm load can be supplied to a level of reliability adopted by the RRO. The resources to meet those requirements include reserve margin provided by excess generation or interruptable load. If the "resource" is located across a posted path, then CBM provides access to the resource. Since "resource" can include generation and load, then the NERC definition is insufficient.

6. In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☒ Yes

☐ No

Comments: There can easily be conflicts for multple LSE's requesting CBM, and there is a problem if the aggregate of all CBM requests exceeds the transmission capacity (R7). Therefore, if this is a new requirement, then there must be some "open season" to collect requests within a fixed time window similar to the Section 2.1 of FERC Order 888 pro-forma tariff. The CBM would be awarded to all comers if there is sufficient capacity but is allocated in lottery fashion if there are more requests than capacity. However, there is the question of the role of ETC in allocating CBM by this method. How much transmission capacity would be offered for CBM? I assume that existing Transmission Reservations cannot be impacted by the CBM bidding process, so only ATC for the planning horizon (if there is any) can be offered. What would an LSE pay for CBM. If it was required to pay the same as it would for a long-term (firm) reservation, then are they really getting CBM or are they getting a long-term firm Transmission Reservation). Some entities interpret Section 2.1 of Order 888 pro-forma tariff to permit bidding on amount and duration to award capacity to the "highest net present value" of the capacity. If there is no charge for CBM, how does the TSE recover lost transmission revenue? It seems that many of these questions must be directed to NAESB

7. Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☒ Yes

☒ No

Comments: It will depend on where the LSE is located in relation to the interface. For example, can an LSE request CBM to access reserve capacity two systems away? Let's say that there are there radially connected systems A is connected to B and C is is only connected to B. LSE#1 in A requests CBM through B to access capacity in C. LSE#2 requests access to capacity in A. In assigning import CBM on the A-B interface, LSE B must consider that the requirement for capacity reserve is due to a shortage in B or in C or to a lesser probability in B+C.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: CBM requirements can change from year to year. For example, if the market responds to price signals and additional generation is built, there is no longer a need for the originally plannned CBM, which should be released to the market. The same is true for entities which are required to install renewable generation or demand-side management programs, which can free existing generation to provide Resource Adequacy without the need for CBM

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments: There should be a high level of proof that CBM is required. An important component is the ability to deliver this energy with single contingencies.

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: R2 requires documention to be "publically released" (published on OASIS) information that is either commercially sensitive or can include Critical Infrastructure Information, the wording of R8 in MOD-008 should be used in MOD-004 to protect information. The process of taking bids on CBM will require modifcations to transmission tariffs Tariffs and Market Rules may have to be updated to reflect the new requirements.

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: The standard does not address the issue of export transmission capacity, since CBE is an import capacity only. An interface involves at least two TSP's: the TSP owning the export side and the TDP owning the import side. Has the drafting team examined the issues around a LSE that requests CBM held back from import but the export TDP can accept reservations without consideration to CBM. Say that the ATC on A-B interface is 200 MW. An LSE in B requires 50 MW of CBM which reduces import ATC on the B side to 150 MW and ATC on the A side remains at 200 MW. A transmission customer in B requests firm reservations on the A-B interface of 200 MW. The A TSP assigns 200 MW to the customer and the B TSP says he can only have 150 MW. The customer takes all 200 MW on the A side but nothing on the B side. Does he then effectively block A-B transactions?.

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: NPCC sets LOLE standards.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: LOLE simulations with assumed transmission capacity, however the answer is around 20% reserve

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | Public Service Commission of South Carolina |
| **Lead Contact:** | **Phil Riley** |
| **Contact Organization:** | **Public Service Commission of South Carolina** |
| **Contact Segment:** | **9** |
| **Contact Telephone:** | **803-896-5154** |
| **Contact E-mail:** | **philip.riley@psc.sc.gov** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mignon L. Clyburn | PSCSC | **SERC** | 9 |
| G. O'Neal Hamilton | PSCSC | **SERC** | 9 |
| John E. "Butch" Howard | PSCSC | **SERC** | 9 |
| Randy Mitchell | PSCSC | **SERC** | 9 |
| C. Robert "Bob" Moseley | PSCSC | **SERC** | 9 |
| David A. Wright | PSCSC | **SERC** | 9 |
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**Background Information**

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin.  Once there is consensus on the requirements, the drafting team will add measures and compliance elements.  Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages.  Comments must be submitted by **June 24, 2007**.  You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☒ Yes

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Comments:

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☐ Yes

☐ No

Comments: Our comments are from a regulatory perspective. This is strictly a technical issue.

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

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☐ Yes

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☒ Yes

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☒ No

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**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: PSCSC reviews reserve margin / resource adequacy of regulated electric utilities in Integrated Resource Plans.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

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Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | Southern Company |
| **Lead Contact:** | **DuShaune Carter** |
| **Contact Organization:** | **Southern Company Services** |
| **Contact Segment:** | |
| **Contact Telephone:** | **205-257-5775** |
| **Contact E-mail:** | **ddcarter@southernco.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| JT Wood | Southern Company Services | **SERC** | 1 |
| Roman Carter | Southern Company Services | **SERC** | 1 |
| Gary Gorham | Southern Company Services | **SERC** | 1 |
| Marc Butts | Southern Company Services | **SERC** | 1 |
| Bill Botters | Southern Company Services | **SERC** | 1 |
| Ron Carlsen | Southern Company Services | **SERC** | 1 |
| Jim Howell | Southern Company Services | **SERC** | 1 |
| Jeremy Bennett | Southern Company Services | **SERC** | 1 |
| Jim Viikinsalo | Southern Company Services | **SERC** | 1 |
| Reed Edwards | Southern Company Services | **SERC** | 5 |
| Dean Ulch | Southern Company Services | **SERC** | 1 |
| Garey Rozier | Southern Company Services | **SERC** | 5 |
| Karl Moor | Southern Company Services | **SERC** | 1 |
| Chuck Chakravarthi | Southern Company Services | **SERC** | 1 |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments:
   5.2 comments: The wording in R5.2 of the proposed standard implies that only one of the identified entities has a role in determining the Load-Serving Entity's resource adequacy requirements. These adequacy requirement could be determined by one or more or none of the listed entities. This requirement should be reworded to require the LSE to list the responsible entity(ies).

   Suggested wording:

R5.2. Identify the entity(ies) (e.g., the municipality, state commission, Regional Transmission Organization/Independent System Operator, Regional Reliability Organization, or Regional Entity) responsible for establishing the Load-Serving Entity's resource adequacy requirements.

5.3 comments: The Load-Serving entity should be added to the list in R5.3.

6.4 comments: The resources referenced in R6.4 should be limited to only those owned or controlled by the Load-Serving entity. Therefore, R6.4 should be reworded and R6.4.2. should be removed.

Suggested wording:
"R6.4. Identify all resources that are owned or controlled by the Load-Serving Entity in its area excluded from serving the Load-Serving Entity's load, including:"

6.5 & 6.7.1 comments: Replace rates with assumptions.

6.7.5 comments (grammatical): Change effect to affect.

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☒ Yes

☐ No

Comments: The request to reserve (set aside) a CBM amount by the LSE should be treated like any other firm transmission service request.

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: For this method, a maximum TTC is calculated for each path, and the CBM set aside is decremented from that path to yield the remaining capacity available for Firm use. The network response for the CBM set aside (POR to POD) is considered and reflected in the TTC when it is calculated. To consider the network response of the CBM set aside for a second time would result in a lower value than the requested amount being decremented from the requested path. This could result in an over-commitment for that path.

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: This could facilitate the opportunity for hording transmission capacity. The standard as drafted requires the LSE to request CBM as needed and maintain the proper documentation as required.

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: This requirement would be best addressed in the resource adequacy standard. If the drafting team decides not to remove R6, more specific comments were made in question 4.

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: R7 requires the Transmission Service Provider to answer a request for CBM within 30 days of receipt. This is inconsistent with the time allowed to answer other firm transmission service requests per Tariff and should be revised to track the tariff requirements for processing long term firm transmission requests.

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments:

In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply:

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: Addressing these concerns should be the role of the resource adequacy drafting team and should be handled in the resource adequacy standard.

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

| | |
|---|---|
| Group Comments (Complete this page if comments are from a group.) | |
| **Group Name:** | SERC Available Transfer Capability Working Group (ATCWG) |
| **Lead Contact:** | **John Troha** |
| **Contact Organization:** | **SERC Reliability Corporation** |
| **Contact Segment:** | **10 - RRO** |
| **Contact Telephone:** | **704-948-0761** |
| **Contact E-mail:** | **jtroha@serc1.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Darrell Pace<br>Helen Stines<br>Eugene Warnecke<br>Don Reichenbach<br>Joachim Francois<br>Ross Kovacs<br>Larry Middleton<br>Jerry Tang<br>John Troha<br>Al McMeekin<br>Stan Shealy<br>Carter Edge<br>DuShaune Carter<br>Bryan Hill<br>Doug Bailey | Alabama Electric Cooperative, Inc<br>Alcoa Power Generating, Inc.<br>Ameren<br>Duke<br>Entergy<br>Georgia Transmission Corporation<br>Midwest ISO<br>Municipal Electric Authority of Georgia<br>SERC Reliability Corporation<br>South Carolina Electric and Gas Company<br>South Carolina Electrica nd Gas Company<br>SERC Reliability Corporation<br>Southern Company Services, Inc. -Trans<br>Southern Company Services, Inc. -Trans<br>Tennessee Valley Authority | **SERC** | 10 |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments:
   1. R8.1 needs clarification.
   2. As drafted, R5.2 implies that only one of the identified entities has a role in determining the Load-Serving Entity's resource adequacy requirements. This adequacy requirement could be determined by more than one or none of the listed entities. This requirement should be reworded to require the LSE to disclose the responsible entity(ies).

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**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☒ No

Comments: We need more clarification on the queing process. What is the definition.

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

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Reply:

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: Chuck Falls | | |
| Organization: Salt River Project | | |
| Telephone: 602 236-0965 | | |
| E-mail: Chuck.Falls@srpnet.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | x | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☐ Yes

   ☐ No

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   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☐ No

   Comments:

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

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☐ No

Comments:

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☐ Yes

☐ No

Comments:

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☐ Yes

☐ No

Comments:

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☐ Yes

☐ No

Comments:

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☐ Yes

☐ No

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**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: SRP sets its Generation Reserve and Resource Adequacy requirements in accordance with WECC Standards.

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: SRP's current planning reserve target is based on historical study work that considered unit availability, load uncertainty, and projected costs associated with carrying different levels of reserves.

Please use this form to submit comments on the 1st draft of standard MOD-004-1 Capacity Benefit Margin. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Clay Young | |
| Organization: | South Carolina Electric & Gas | |
| Telephone: | 803-217-9129 | |
| E-mail: | cyoung@scana.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

Capacity Benefit Margin (CBM) is one component of the TTC/ATC/AFC calculations, the calculation, verification, preservation, and use of which is detailed in draft standard MOD-004-1.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-004-1 Capacity Benefit Margin. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and MOD-004-1 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "CBM Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.

   ☒ Yes

   ☐ No

   Comments:

4. The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

**5.** In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**6.** In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.

☐ Yes

☐ No

Comments:

**7.** Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**8.** If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**9.** Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**10.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**11.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments: I suggest the following changes to the definitions: Transmission Service Request: A request by the Transmission Customer to the Transmission Service Provider for transmission service to move energy from a Point of Receipt to a Point of Delivery.

**In R1 requirements, the multiple meanings of "its" is confusing. Also, Network Customers can have many PORs and PODs on a system, there could be several hundred combination paths, an unmanagable number. I suggest the following language for R1 requirements.**

**R1. The Transmission Service Provider shall make publicly available:**

**R1.1. Its procedure for a Load-Serving Entity to request a CBM import MW requirement on each Point of Receipt for meeting its resource adequacy requirement (i.e., its procedure for setting aside of Transfer Capability in the form of CBM to maintain a Load-Serving Entity's resource adequacy requirement).**

**R1.2. Its procedure and assumptions for allocating CBM over each path or Flowgate.**

**R1.3. Its procedure for CBM use (i.e., its procedure for scheduling of energy over transmission capacity set aside as CBM).**

**R1.4. The most recent values of CBM used for calculating Available Transmission Capacity (ATC) or Available Flowgate Capability (AFC) for each timeframe by Flowgate or path, as applicable.**

**(If this comment is adopted, this same type of change is needed in other places in this standard)**

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In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

**12.** What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)?
Reply: .

**13.** With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource.

Reply: 1 and 4

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Modifications made 11/1/07 to this page and page 36.

**Consideration of Comments on 1st Draft of Standard MOD-004-1 — Capacity Benefit Margin (Project 2006-07)**

The ATC Standard Drafting Team thanks all commenters who submitted comments on Draft 1 of the MOD-004-1 Capacity Benefit Margin. This standard was posted for a 30-day public comment period from May 25 through June 24, 2007. The drafting team asked stakeholders to provide feedback on the standard through a special standard Comment Form.

There were 20 sets of comments, including comments from 97 different people from more than 45 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received from stakeholders, comments from the cooperative effort with NAESB in developing associated business practices, and comments received from FERC staff, the drafting team has significantly redrafted the standard. The changes have been so extensive that the revised standard bears very little resemblance to the last posted draft. Major changes include:

- Added two defined terms: Generation Capability Import Requirement (GCIR) and Capacity Benefit Margin Implementation Document (CBMID)
- Revised the proposed definitions of Flowgate, Total Flowgate Capability, and Available Flowgate Capability – but moved these definition to the draft MOD-030 standard
- Eliminated Transmission Reservation and Transmission Service Request as proposed defined terms
- Modified the Purpose statement to clarify that the purpose is to ensure reliable system operations rather than accurate calculation of transfer capabilities
- Adopted the use of the defined term, 'Posted Path' to match the definition used by FERC and NAESB (without the explanatory information at the end of the definition)
- Modified the description of the Load-Serving Entities that must comply with the standard so that the standard now applies to all Load-Serving Entities. While the standard does not require that all LSEs must request CBM, it does allow any Load-Serving Entity to use CBM in a capacity deficiency emergency even if they did not originally request to have it set aside. (They would, however, only be allowed to use CBM if those, who originally asked for it, were not using it).
- Modified R1 so that it requires a Capacity Benefit Margin Implementation Document rather that includes a set of procedures rather than just identifying the list of procedures
- Eliminated the posting elements of R1 and R2 as NAESB will address all public postings in its associated business practices but retained the other aspects of the requirements.
- R2 which required the Transmission Service Provider to make copies of its models used to determine CBM available to others has been modified and merged into R7 in the revised standard.
- Added more details to R3 to clarify that the Transmission Service Provider must first determine the amount of CBM to allocate for each CBM request, then set CBM for each

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Posted Path or Flowgate according to a set of criteria. The revised requirement (R4 in the revised standard merges portions of R3 and R7.

- R4 required the Load-Serving Entity that wants CBM to submit a request for CBM at least annually. This requirement has been modified to expand on the scope of documentation that must be provided to support the request for CBM. For example, in the revised requirement the Balancing Authority that has the generation to be imported must be identified, resource studies that show the need for CBM must be provided, etc. A sub-requirement was added to require the Load-Serving Entity to update its CBM request at least once every 31 days.
- R5 was structured as a data retention requirement for the Load-Serving Entity. Many of the items listed have been moved into the revised R3 and must be supplied to the Transmission Service Provider with the request for CBM. The drafting team deleted the data retention aspect from the requirement. Data retention is addressed in the compliance section of the revised standard and is identified on a requirement-by-requirement basis.
- R6 required the Load-Serving Entity to follow certain steps if it performed probabilistic studies for determining CBM import MW requirements and the drafting team removed the requirement from the revised standard. The revised standard assumes that studies have been conducted and requires the results of the studies be provided with a request for CBM, but the revised standard does not identify 'how' to perform these studies.
- R7 was merged into the revised R3. The portion of R7 that required the Transmission Service Provider to make a CBM Import Entitlement Report 'publicly available' has been removed from the revised standard. NAESB is developing business practices to address all of the 'posting' requirements associated with the set of ATC-related standards.
- R8 stated an 'allowance' for the Load-Serving Entity to request CBM under certain conditions. The requirement did not include a statement of required performance and several commenters indicated it was difficult to understand. The drafting team removed this from the revised standard.
- R9 required the Balancing Authority to waive timing and ramping requirements for scheduling of energy over transmission capacity set aside as CBM. This requirement was revised to require both the Balancing Authority and Transmission Service Provider to adhere to this requirement.
- R10 required the Load-Serving Entity to declare a NERC Energy Emergency Alert (EEA) level 2 before scheduling energy over transmission capacity set aside as CBM. This requirement was modified to clarify that it is not the Load-Serving Entity that 'declares' the EEA, but the Load-Serving Entity is 'experiencing' an EEA level 2. (See R8 in the revised standard)
- R11 required the Load-Serving Entity to provide a report to its Transmission Service Provider after scheduling energy over transmission capacity set aside as CBM and to retain that report for five years. The drafting team removed this requirement as any reporting requirements can be addressed under the compliance section of the standard as 'Exception Reporting'.
- R12 required the Transmission Service Provider to make the report from R11 'publicly available' and since the report is no longer required and NAESB is addressing all posting requirements, this requirement was removed from the revised standard.
- R13 required the Transmission Planner to consider CBM import MW requirements in its planning processes. This requirement has been merged into ~~R4~~ R5 and more details have been added to the requirement for the Transmission Planner.

- R14 required the Load-Serving Entity to avoid use of the same uncertainties for both CBM and TRM. A similar requirement is within MOD-008 — Transmission Reliability Margin and the drafting team removed R14 from MOD-004 to avoid having the same requirement in more than one standard.
- Added measures and compliance elements.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Backup_Facilities.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Anita Lee (G5) | AESO | | ✓ | | | | | | | | |
| 2. | Jason Murray (G1) | AESO | | ✓ | | | | | | | | |
| 3. | Darrell Pace (G9) | Alabama Electric Coop | | | | ✓ | ✓ | ✓ | | | | |
| 4. | Heln Stines (G9) | Alcoa Power Generating | | | | | | ✓ | ✓ | ✓ | | |
| 5. | Ken Goldsmith (G6) | ALT | ✓ | | | | ✓ | | | | | |
| 6. | Eugene Warnecke (G9) | Ameren | | | ✓ | | | ✓ | | | | |
| 7. | E. Nick Henery (G2) | APPA | ✓ | | | | | | | | | |
| 8. | Jerry Smith (G1) | APS-TP | | | | | | | | | | |
| 9. | Dave Rudolph (G6) | BEPC | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 10. | Steve Tran (G1) | BP TX | | | | | | | | | | |
| 11. | Abbey Nulph (G1) (I) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 12. | Rebecca Berdahl (G1) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 13. | Steve Knudsen (G1) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 14. | Charles Mee (G1) | CA Dept Water & Power | | | | | | | | | | |
| 15. | Greg Ford (G1) | CISO-TP | | ✓ | | | | | | | | |
| 16. | Don Reichenbach (G9) | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 17. | Greg Rowland | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 18. | Joachim Francois (G9) | Entergy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 19. | Ed Davis (G3) | Entergy Services | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 20. | George Bartlett (G3) | Entergy Services | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 21. | Jim Case (G3) | Entergy Services | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 22. | Narinder Saini (G3) | Entergy Services | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 23. | Steve Myers (I) (G5) | ERCOT | | ✓ | | | | | | | | ✓ |
| 24. | Patricia vanMidde (G1) | FERC Case MRG, Sempra | | | | | | | | | | |
| 25. | Dave Folk (G4) | FirstEnergy | ✓ | | ✓ | | ✓ | ✓ | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 26. | Phil Bowers (G4) | FirstEnergy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 27. | Richard Kovacs (G4) | FirstEnergy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 28. | Ross Kovacs (G9) | Georgia Transmission Co | ✓ | | ✓ | | | | | | | |
| 29. | Joe Knight (G6) | Great River Energy | ✓ | | ✓ | | ✓ | | | | | |
| 30. | Ron Falsetti (I) (G5) | IESO | | ✓ | | | | | | | | |
| 31. | Lou Ann Westerfield (G1) | IPUC-SP | | | | | | | | | | |
| 32. | Matt Goldbert (G5) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 33. | Rian Thumm | ITC | ✓ | | | | | | | | | |
| 34. | Sueyen McMahon (G1) | LADWP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 35. | Eric Ruskamp (G6) | LES | ✓ | | ✓ | | ✓ | | | | | |
| 36. | Michelle Rheault | Manitoba Hydro | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 37. | Robert Coish (G6) | Manitoba Hydro | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 38. | Tom Mielnik (I) (G6) | MidAmerican Energy Co (MEC) | | | ✓ | | | | | | | |
| 39. | Dennis Kimm | MidAmerican Energy Generation/Trading (MEC – Trading) | | | ✓ | | ✓ | ✓ | | | | |
| 40. | Larry Middleton (G9) | Midwest ISO | | | | | | | | | | |
| 41. | Bill Phillips (G5) | MISO | | ✓ | | | | | | | | |
| 42. | Terry Bilke (G6) | MISO | | ✓ | | | | | | | | |
| 43. | Carol Gerou(G6) | MP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 44. | Mike Brytowski (G6) | MRO | | | | | | | | | | ✓ |
| 45. | Jerry Tang (G9) | Municipal Electric Authority of GA | ✓ | | ✓ | | ✓ | | | | | |
| 46. | Jerry Teag | Municipal Electric Authority of GA (MEAG) | ✓ | | ✓ | | ✓ | | | | | |
| 47. | Matt Schull (G2) | NCMPA #1 | | | | | ✓ | | | | | |
| 48. | Robert W. Creighton | Nova Scotia Power, Inc | ✓ | | | | | | | | | |
| 49. | Jim Castle (G5) | NYISO | | ✓ | | | | | | | | |
| 50. | Todd Gosnell (G6) | OPPD | ✓ | | ✓ | | | ✓ | | | | |
| 51. | Brian Weber (G1) | Pacificorp | ✓ | | | | ✓ | | | | | |
| 52. | C. Robert Moseley (G7) | PSC of SC | | | | | | | | | ✓ | |
| 53. | David A. Wright (G7) | PSC of SC | | | | | | | | | ✓ | |
| 54. | G. O'Neal Hamilton (G7) | PSC of SC | | | | | | | | | ✓ | |
| 55. | John E. Howard (G7) | PSC of SC | | | | | | | | | ✓ | |
| 56. | Mignon Clybum (G7) | PSC of SC | | | | | | | | | ✓ | |
| 57. | Phil Riley (G7) | PSC of SC | | | | | | | | | ✓ | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 58. | Randy Mitchell (G7) | PSC of SC | | | | | | | | | ✓ | |
| 59. | Chuck Falls (I) (G1) | Salt River Project (SRP) | ✓ | | | | | | | | | |
| 60. | Al McMeekin (G9) | SC Electric & Gas | | | ✓ | | ✓ | ✓ | | | | |
| 61. | Stan Shealy (G9) | SC Electric& Gas | | | ✓ | | ✓ | ✓ | | | | |
| 62. | Carter Edge (G9) | SERC | | | | | | | | | | ✓ |
| 63. | John Troha (G9) | SERC | | | | | | | | | | ✓ |
| 64. | Bob Schwermann (G1) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 65. | Brian Jobson (G1) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 66. | Dick Buckingham (G1) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 67. | Dilip Mahendra (G1) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 68. | W. Shannon Black (G1) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 69. | Phil Odonnell (G1) | SMUD- Ops | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 70. | Bill Botters (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 71. | Bryan Hill (G9) | Southern Company Services | | | | | ✓ | | | | | |
| 72. | Chuck Chakravarthi (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 73. | Dean Ulch (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 74. | DuShane Carter (G8) (G9) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 75. | Garey Rozier (G8) | Southern Company Services | | | | | ✓ | | | | | |
| 76. | Gary Gorham (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 77. | J. T. Wood (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 78. | Jeremy Bennett (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 79. | Jim Howell (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 80. | Jim Viikinsalo (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 81. | Karl Moor (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 82. | Marc Butts (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 83. | Reed Edwards (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 84. | Roman Carter (G8) | Southern Company | ✓ | | | | ✓ | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| | | Services | | | | | | | | | | |
| 85. | Ron Carlsen (G8) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 86. | Charles Yeung (G5) | SPP | | ✓ | | | | | | | | |
| 87. | Casey Sprouse (G1) | Sr. Term Marketer | | | | | | | | | | |
| 88. | Maria Denton (G1) | SRP | | | | | | | | | | |
| 89. | Terri M. Kuehneman (G1) | SRP System Operation | | | | | | | | | | |
| 90. | Raquel Agular (G1) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 91. | Ron Belval (G1) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 92. | Doug Bailey (G9) | TVA | ✓ | | ✓ | | ✓ | | | | | |
| 93. | Jim Haigh (G6) | WAPA | ✓ | | | | | | | | ✓ | |
| 94. | Raymond Vojdani (G1) | WAPA | | | | | | | | | ✓ | |
| 95. | Mike Wells (G1) | WECC | | | | | | | | | | ✓ |
| 96. | Neal Balu (G6) | WPS | | | ✓ | ✓ | ✓ | ✓ | | | | |
| 97. | Pam Oreschnick (G6) | XEL | ✓ | | ✓ | | ✓ | ✓ | | | | |

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – WECC MIC MIS ATC Task Force
G2 – APPA
G3 – Entergy Services
G4 – FirstEnergy
G5 – IRC Standards Review Committee
G6 – MRO
G7- PSC of SC
G8- Southern Company
G9- SERC ATC WG

## Index to Questions, Comments, and Responses

1. **The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.**

**Summary Consideration:** Most stakeholders who responded to this question indicated a preference for keeping the requirements in a single standard. Based on responses received, the drafting team has retained the requirements in a single standard.

| **Question #1** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| BPA | | ☑ | R1 of MOD-004-1 needs to clarify that CBM procedures need only be made publicly available if the Transmission Service Provider uses CBM. |
| **Response:** All public posting requirements will be addressed by NAESB, however, FERC has indicated that the TSP must offer CBM to its LSEs, and as such, the standard requires all TSPs to prepare and maintain CBM procedures. | | | |
| IESO<br>IRC SRC | | ☑ | We do not agree with combining all of the above mentioned standards in one standard (MOD-004). This coupled with the need to make a distinction between the ATC calculation methods used and the descriptive procedure for resource adequacy assessment has made the new MOD-004 very convoluted, and the requirements difficult to follow and measured. If combining some standards of related objective is desired, a more manageable and appropriate alternative is to divide these 4 standards into two groups - one on the determining and verifying the calculation of CBM and the other on the use and reporting of use of CBM. |
| **Response:** Based on stakeholder responses received, the consensus is to keep the single standard. Note that several requirements have been removed from the revised standard, including the requirements referencing resource adequacy. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC comments. | | | |
| ITC | ☑ | ☑ | We highly recommend sticking to one single standard to address all of the CBM requirements. |
| **Response:** Most responders agree and based on stakeholder responses received, the consensus is to keep the single standard. | | | |
| Entergy Services | ☑ | | Entergy supports combination of CBM Calculation, verification, preservation, and use into one standard. |
| **Response:** Most responders agree and based on stakeholder responses received, the consensus is to keep the single standard. | | | |
| Duke Energy | ☑ | | |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC Task Force | ☑ | | |
| APPA | ☑ | | |
| FirstEnergy | ☑ | | |
| MEAG | ☑ | | |
| MEC Trading | ☑ | | |
| MEC | ☑ | | |
| MRO | ☑ | | |
| Nova Scotia Power | ☑ | | |
| PSC of SC | ☑ | | |
| Southern Co Svcs | ☑ | | |
| SERC ATCWG | ☑ | | |

2. **The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.**

**Summary Consideration:** Most stakeholders who responded to this question indicated that the drafting team has adequately responded to all of the Commission's directives in Order 890 and 693, however there were some suggestions for modifications that would improve compliance with the directives.

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The Standard, as written, will continue to allow the applicable functions to define CBM without any amount of consistency, which is what Order 890 wanted the Standards to accomplish. In addition, the Standard does not recognize that ATC is calculated on 3 different time horizons and CBM transmission reservation will vary from the Monthly to the Daily to the Hourly calculations. |
| **Response:** The standard requires the LSE "prove" and document its need for CBM. It is quite possible that these requirements will not be consistent across the country. By law, the ERO cannot determine these requirements but is fully responsible for ensuring that the LSE is stating these requirements accurately as determined by "the entity responsible for establishing the Load-Serving Entity's resource adequacy requirements." However, it is expected that most requirements will be based on some LOLE requirement. The compliance monitor (now called the Compliance Enforcement Authority) will be required to ensure that the LSE is not deviating from the resource adequacy requirements of the "entity responsible" for these requirements. | | | |
| MEC Trading<br>MEC<br>MRO | | ☑ | 1. R3.1.2, R3.2.1, and R3.3.1 should be clarified by matching the language in FERC 890 as follows: "The Transmission Service Provider shall not include transmission capacity set aside for THE INCREMENTAL POWER FLOWS RESULTING FROM reserve sharing in CBM." It could be that CBM is reserved to the LSE's generation reliability criteria which is based upon a reserve sharing requirement. It is just that those flows that result from increment power flows resulting from reserve sharing are to be included in TRM.<br><br>2. In R1.1, it would be better to include the exact language from Order 890 in the parantheses to explain the resource adequacy requirements that are to be included in the CBM, as follows: "…..for meeting its resource adequacy requirement (i.e., its procedure for setting aside of Transfer Capability in the form of CBM to MEET a Load-Serving Entity's GENERATION RELIABILITY CRITERIA.)<br><br>890 and 693 also require some level of consistency and the methodology requirements for CBM appear to be fill-in-the-blank. |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** 1.) The drafting team agrees that this is what FERC intended. Please see the revised requirement in the summary consideration above. As defined, CBM is a transaction and you can't subtract flows from transactions. In the revised standard's R4.2.1, we subtract "the transfer capability set aside for reserve sharing" because this is a transaction quantity. Posted Paths are transaction paths (ATC)<br><br>In 4.2.2 we subtract "the 'impact' of transfer capability set aside for reserve sharing. The "impact" is a flow quantity. Flowgates use "flows" and not transactions (AFC). This "impact" equals what FERC calls the "incremental power flows resulting from reserve sharing".<br><br>2.) The existing language is appropriate based on FERC's use of the term in attachment C, paragraph e of the pro-forma OATT included with Order 890.<br>The standard drafting team has attempted to increase the consistency of CBM determination in the latest revision. Please see the summary of changes to requirement on the cover page of this report. | | | |
| Nova Scotia Power | ☑ | ☑ | What happened to the requirement that CBM is a planning quantity only and tends to zero in the operating horizon. Does this mean that CBM cannot be used for non-firm import transactions? |
| **Response:** This requirement has been addressed in the specific ATC standards, such that non-firm ATC is increased by unscheduled CBM. (See the algorithms for the determination of ATC and AFC in MOD-028, MOD-029 and MOD-030.) | | | |
| IESO<br>IRC SRC | ☑ | | In a general sense, yes, but the amount of detail seems to exceed the requirements implied by the FERC directives, which has resulted in repetitions and circular requirements. For example, R5 repeats most of R4's requirements, except in R5 the retention periods are specified, which arguably should be covered in the compliance section. Another example is R6.1 suggests that the CBM is calculated as a parameter or a by-product of a resource adequacy assessment, but R6.2 requires that the load assumption of the CBM study be the same as that assumed in the the resource adequacy assessment. |
| **Response:** You are correct in that CBM is a by-product of resource adequacy assessments required by whatever entity directs the LSE to meet their requirements. The standard drafting team has attempted to clarify and improve the standard to consolidate where possible. R5 was deleted and is addressed in the compliance section of the standard under data retention. R6 was also deleted from the revised standard. | | | |
| ERCOT | ☑ | | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC comments. | | | |
| Duke Energy | ☑ | | |
| Entergy Services | ☑ | | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| FirstEnergy | ☑ | | |
| ITC | ☑ | | |
| PSC of SC | ☑ | | |
| Southern Co Svcs | ☑ | | |

3. **The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.**

**Summary Consideration:** Most commenters who responded to this question supported the applicability section of the standard – there were suggestions to remove the 'qualifying language' associated with the Load-Serving Entity, and the drafting team has removed this qualifying language – the revised standard is applicable to all Load-Serving Entities. There were also some suggestions to clarify the responsibilities of the Transmission Planner. As revised, the Transmission Planner is responsible for two requirements – for allocating CBM for use in the long-term horizon (beyond one year) and for providing copies of the supporting data used to allocate CBM. The Drafting team has rewritten the standard to be more clear, and to explicitly explain the responsibilities of the Transmission Planner.

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | All throughout this Standard the author has Reliability Functions performing duties that are counter to those duties prescribe in the Functional Model. In addition, the SDT has incorrectly included requirements for scheduling of energy, maintenance schedules, and so-on, which are preformed by other Reliability Functions in other Standards. |
| **Response:** We have attempted to address this in the new draft of the standard. Please see the summary of revisions made to the standard on the cover page of this document. | | | |
| MEC | | ☑ | I believe that the Functional Entity as provided in A.4.1.1 should not be qualified, for example, A.4.1.1 should just list Load-Serving Entity. However, if the Standards Drafting Team continues to list only those "Load-Serving Entity that is entitled and would like to have transmission capability set aside in the form of CBM" then I recommend that "would like" changed to "needed" in other words, reservation of CBM should not be based on likes but based on needs as demonstrated with the studies to be provided in support of the CBM. |
| **Response:** We have modified the applicability for the Load-Serving Entity to eliminate the qualifiers in support of your suggestion. | | | |
| MRO | | ☑ | The MRO believes that the Functional Entity as provided in A.4.1.1 should not be qualified, for example, the MRO recommends that A.4.1.1 just list Load-Serving Entity. However, if the Standards Drafting Team continues to list only those "Load-Serving Entity that is entitled and would like to have transmission capability set aside in the form of CBM" then the MRO recommends that "would like" changed to "needed" in other words, reservation of CBM should not be based on likes but based on needs as demonstrated with the studies to be provided in support of the CBM. |
| **Response:** We have modified the applicability for the Load-Serving Entity to eliminate the qualifiers in support of your | | | |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| suggestion. | | | |
| IESO<br>IRC SRC | | ☑ | There is only one requirement for the Transmission Planner, and that is in R13. However, we do not feel that R13 belongs to this standard. The inclusion of requested and projected CBM values in its planning process belongs to a standard that stipulate requirements for transmission planning. If this requirement is removed or relocated, then TP does not need to be included as an applicable entity. Similar thoughts for the applicability of the BA. |
| **Response:** We have rewritten the standard to more fully explain the role of the Transmission Planner. Note that the drafting team did ask stakeholders to weigh in on whether all requirements related to CBM should be contained within a single standard and most commenters indicated support for having all CBM-related requirements in the single standard. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC comments. | | | |
| WECC MIC MIS ATC Task Force | ☑ | | |
| Duke Energy | ☑ | | |
| Entergy Services | ☑ | | |
| FirstEnergy | ☑ | | |
| ITC | ☑ | | |
| MEAG | ☑ | | |
| MEC Trading | ☑ | | |
| PSC of SC | ☑ | | |
| Southern Co Svcs | ☑ | | |
| SERC ATCWG | ☑ | | |

4. **The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.**

**Summary Consideration:** Please see the cover page of this report for a complete list of the modifications made to the standard based on stakeholder comments and discussions with NAESB and FERC.

| **Question #4** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| BPA | | | The discussion of CBM in Order 890 and NERC's definition of CBM refer only to generation reliability requirements, not resource adequacy requirements. Please clarify what is meant by "resource adequacy requirements". |
| **Response:** The "resource adequacy requirement" is the same as the "planning" reserve margin as defined by "the entity responsible for establishing the Load-Serving Entity's resource adequacy requirements." For those entities with LOLE requirements, it is usually the LSE's dependence on external resources to meet those LOLE requirements. The drafting team did remove the resource adequacy requirements from the revised standard – the revised standard assumes that the studies have been conducted and requires that the study documentation be provided as part of the request for CBM. | | | |
| WECC MIC MIS ATC Task Force | | ☑ | See general comments. |
| **Response:** See response to general comments. | | | |
| APPA | | ☑ | The Standard has Functional Entities performing duties that is contrary to the Functional Model's directions. Examples are in Requirement R 1.3 and R 10; the scheduling of energy over the transmission capacity that is designated CBM only occur during the active hour to meet "generation reliability requirements." The Balancing Authority is the only Function that has that authority to schedule energy during the real-time. This Standard, as written, will create an environment where confusion will exist during critical situation in the real-time and cause the possibility of a command and control break down during a critical situation in the real-time. To require the Transmission Service Provider or the Load Serving Entity to be responsible for declaring emergencies or scheduling energy during those emergencies will create very non-reliable situation. A large part of this Standard needs to be rewritten to ensure reliable operations. |
| **Response:** Requirement 1.3 in the first draft of this standard required the Transmission Service Provider to document its procedure for an LSE to request CBM. The drafting team did not change the applicability for this requirement as it is the Transmission Service Provider that must have this procedure.<br>R10 in the first draft of this standard required the Transmission Service Provider to declare a NERC EEA 2 – and this has been revised. In the revised standard, this requirement (now R8) clarifies that the LSE cannot request to schedule energy over Firm Transfer Capability set aside as CBM unless the LSE is experiencing a NERC EEA 2 . You are correct that it is not the | | | |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| LSE that 'declares' the EEA 2.<br>As revised, there are no requirements for the Transmission Service Provider or Load-Serving Entity to declare emergencies. | | | |
| IESO<br>IRC SRC | | ☑ | Please see the above comments on some of the repetitive and extraneous requirements. |
| **Response:** See responses to previous questions. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See the response to IRC comments. | | | |
| MEAG | | ☑ | R8.1 needs clarification. |
| **Response:** Several commenters indicated that R8.1 needs clarification and the intent of this requirement has been absorbed into R10 of the revised standard. | | | |
| MEC Trading | | ☑ | Many of the requirements are fill-in-the-blank (Isn't R1.2 a requirement to "tell me how you do it? and shouldn't it be "this is how you do it") |
| **Response:** We have attempted to eliminate the fill-in-the-blank elements of the standard. The drafting team is trying to find the right balance between mandating that all entities perform the calculations the same way, and allowing some latitude for justifiable differences. As the standards are implemented and more documents become 'transparent' the standard may need to be revised to eliminate any 'fill-in-the-blank' elements if there is evidence that this flexibility is adversely impacting either reliabilty or energy markets. | | | |
| MEC | | ☑ | 1. I recommend that R2 be changed from "following a request by an entity with a valid need for such information" to "following a request by a Functional Entity with a valid need for such information, subject to security and confidentiality requirements."<br><br>2. R5.3 does not represent all the conditions that organizationally exist, therefore, I recommend that a bullet be added under R5.3 as follows" "Planning Reserve Sharing Group reserve margin to meet the Regional Reliability Organization resource adequacy requirements".<br><br>3. R6.2 should refer to "a load forecast that has a 50/50% probability of occurrence". This means that there is a 50% probability that the load will actually be below the forecast and there is a 50% probability that the load is above the forecast. A statement that it is a 50% probability forecast has no mening without adding some information to it. For example, is it a 50% Confidence Interval forecast in which case it would be two numbers with 50 percent probability that the actual number will be within the two numbers. |
| **Response :** 1. R2 has been revised such that the portion of the requirement that aimed at making information 'publicly available' was deleted – and the portion that focused on sharing information with reliability-related entities was moved into R7 of the revised standard. R7 of the revised standard has two parts – the first part requires that the Transmission Service Provider give data and information to its Transmission Operators (without needing a request) within 7 days of a modification | | | |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| to CBM – the second part requires the Transmission Service Provider to share the same information with other reliability-related entities that request the information within 7 days of the request. With these changes, the confidentiality issue should not be a concern. All the requirements that indicated that an entity had to make data or information 'publicly available' have been removed from the standard. Public availability of information will be addressed by NAESB in business practices. This modification supports the intent of your suggestion.<br>2. R5 was merged into R3 in the revised standard except that the retention of this data is now addressed in the compliance section of the revised standard. The revised standard requires that all reserve margin requirements be documented – see R3.1.2 in the revised standard. This change supports the intent of your suggestion.<br>3. R6.2 - All of the resource adequacy requirements were removed from the standard as they will be addressed in greater detail in a new resource adequacy standard under development with a different SAR and drafting team. As revised, this standard assumes that the resource adequacy studies have taken place and the studies and study results must be made available as support for a request for CBM. | | | |
| | | ☑ | 1. MRO recommends that R2 be changed from "following a request by an entity with a valid need for such information" to "following a request by a Functional Entity with a valid need for such information, subject to security and confidentiality requirements."<br>2. R5.3 does not represent all the conditions that organizationally exist in the MRO, therefore, we recommend that a bullet be added under R5.3 as follows" "Planning Reserve Sharing Group reserve margin to meet the Regional Reliability Organization resource adequacy requirements".<br>3. R6.2 should refer to "a load forecast that has a 50/50% probability of occurrence". This means that there is a 50% probability that the load will actually be below the forecast and there is a 50% probability that the load is above the forecast. A statement that it is a 50% probability forecast has no mening without adding some information to it. For example, is it a 50% Confidence Interval forecast in which case it would be two numbers with 50 percent probability that the actual number will be within the two numbers. |
| **Response:** 1. R2 has been revised such that the portion of the requirement that aimed at making information 'publicly available' was deleted – and the portion that focused on sharing information with reliability-related entities was moved into R7 of the revised standard. R7 of the revised standard has two parts – the first part requires that the Transmission Service Provider give data and information to its Transmission Operators (without needing a request) within 7 days of a modification to CBM – the second part requires the Transmission Service Provider to share the same information with other reliability-related entities that request the information within 7 days of the request. With these changes, the confidentiality issue should not be a concern. All the requirements that indicated that an entity had to make data or information 'publicly available' have been removed from the standard. Public availability of information will be addressed by NAESB in business practices. This modification supports the intent of your suggestion.<br>2. R5 was merged into R3 in the revised standard except that the retention of this data is now addressed in the compliance section of the revised standard. The revised standard requires that all reserve margin requirements be documented – see R3.1.2 in the revised standard. This change supports the intent of your suggestion. | | | |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| 3. R6.2 - All of the resource adequacy requirements were removed from the standard as they will be addressed in greater detail in a new resource adequacy standard under development with a different SAR and drafting team. As revised, this standard assumes that the resource adequacy studies have taken place and the studies and study results must be made available as support for a request for CBM. | | | |
| Southern Co Svcs | | ☑ | 5.2 comments: The wording in R5.2 of the proposed standard implies that only one of the identified entities has a role in determining the Load-Serving Entity's resource adequacy requirements. These adequacy requirement could be determined by one or more or none of the listed entities. This requirement should be reworded to require the LSE to list the responsible entity(ies).<br><br>Suggested wording:<br>R5.2. Identify the entity(ies) (e.g., the municipality, state commission, Regional Transmission Organization/Independent System Operator, Regional Reliability Organization, or Regional Entity) responsible for establishing the Load-Serving Entity's resource adequacy requirements.<br><br>5.3 comments: The Load-Serving entity should be added to the list in R5.3.<br><br>6.4 comments: The resources referenced in R6.4 should be limited to only those owned or controlled by the Load-Serving entity. Therefore, R6.4 should be reworded and R6.4.2. should be removed.<br><br>Suggested wording:<br>"R6.4. Identify all resources that are owned or controlled by the Load-Serving Entity in its area excluded from serving the Load-Serving Entity's load, including:"<br><br>6.5 & 6.7.1 comments: Replace rates with assumptions.<br><br>6.7.5 comments (grammatical): Change effect to affect. |
| **Response:** The data retention aspects of R5 were modified and moved to the compliance elements of the standard – the requirement to have the data and information has been absorbed into Requirement 3 in the revised standard.<br>The revised standard includes the following language: "Identification of all applicable reserve margin and resource adequacy requirements, and the entity(ies) responsible for establishing them. . ." in support of your suggestion relative to R5.2.<br><br>R5.3 was assigned to the Load-Serving Entity, and required the Load-Serving Entity to retain documentation relative to the determination of CBM. The drafting team isn't sure how to incorporate the suggested modification.<br>The drafting team removed the requirement (R6) that addressed probabilistic studies. This standard has been revised to assume that the studies have taken place. | | | |
| SERC ATCWG | | ☑ | 1. R8.1 needs clarification. |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | 2. As drafted, R5.2 implies that only one of the identified entities has a role in determining the Load-Serving Entity's resource adequacy requirements. This adequacy requirement could be determined by more than one or none of the listed entities. This requirement should be reworded to require the LSE to disclose the responsible entity(ies).<br><br>3. The resources referenced in R6.4 should be limited to only those owned or controlled by the Load-Serving entity. Therefore, R6.4 should be reworded to state, and R6.4.2. should be removed. |
| **Response:** 1. Based on stakeholder comments, R8.1 was removed from the standard.<br>2. The data retention aspects of R5 were modified and moved to the compliance elements of the standard – the requirement to have the data and information has been absorbed into Requirement 3 in the revised standard.<br>The revised standard includes the following language: "Identification of all applicable reserve margin and resource adequacy requirements, and the entity(ies) responsible for establishing them. . ." in support of your suggestion relative to R5.2.<br><br>3. The drafting team removed the requirement (R6) that addressed probabilistic studies. This standard has been revised to assume that the studies have taken place. | | | |
| Entergy Services | ☑ | | |
| FirstEnergy | ☑ | | |
| ITC | ☑ | | |
| PSC of SC | ☑ | | |

**5. In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.**

**Summary Consideration:** There was no consensus amongst those who responded to this question. Based on a review of all the detailed comments submitted, the Drafting Team believes that the current NERC definition of CBM is adequate.

| **Question #5** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC Task Force | | ☑ | GRR is used as a defined term without a definition. If retained as a defined term it needs a definition.<br>As to the definition of CBM, the Team suggests a more specific NERC CBM definition as follows:<br>"Capacity Benefit Margin"<br>CBM is the amount of firm import transmission capability, requested by the LSE, to exclusively serve identified load only during periods of emergency generation deficiencies extending beyond the beginning of the scheduling hour in which the emergency generation deficiency occurs."<br>Commentary:<br>The "located on" was excluded from the suggested language because the definition would have to generically identify the system of "that TSP" – which TSP is "that"? This is impractical when the definition is written from the standpoint of the LSE as opposed to the existing TSP paradigm.<br><br>"…[T]o enable access by the LSE to generation from interconnected systems" was deleted as that is conveyed in the determinant "import" as suggested in the new definition.<br><br>"Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements" was excluded from the suggested definition as it is merely commentary and adds nothing to the definition. |
| **Response:** GRR was not intended to be treated as a defined term, and it is not indicated as such in the actual definition. GRR does not completely define CBM. The revised MOD-004 does not use the acronym, 'GRR.' | | | |
| APPA | | ☑ | The definition of CBM is causing the industry to calculate CBM is many different ways. The definition of CBM states that CBM is used to meet an entity's "generation reliability requirements." Some entities are saying that the use of CBM to handle "Planning Reserves" is the correct and reserve transmission capacity as CBM to bring in energy from energy resources outside the BA's area that were determined when the entity calculated "Planning Reserves." Other entities calculate the amount of CBM capacity based on "Operating Reserves." As the definition of CBM is written either one could be correct or incorrect. This definition worked well when the industry maintained reliability of the BES from Reliability Policies. |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | The CBM definition's undefined term "generation reliability requirement" allows an excessive amount of transmission capacity to be removed from the BES as CBM and prevents the correct amount of ATC to be placed on the market for use by other entities. In addition, the definition of CBM is so general it is impossible for a Compliance Program to determine if an entity is non-compliant. |
| **Response:** The intent of all of the new requirements is that the LSE must prove, to the compliance monitors (now called Compliance Enforcement Authority) satisfaction, that it is properly stating its need for transmission margin to meet its "resource adequacy" requirements. It is the full intent of the language used in the requirements to prevent the overstatement of CBM that you imply will happen. The compliance monitor will have significant responsibility to make this determination. | | | |
| IESO<br>IRC SRC | | ☑ | We should redefine it along the line that is provided in FERC's directive that CBM is required for generation deficiency only. |
| **Response:** See summary response, | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC comments. | | | |
| ITC | | ☑ | The NERC glossary and CBM definition should be expanded to include other terms, such as "Resource Adequacy" to fully address this issue. This expansion may come as a result of future LSE requests for CBM based on a justification not currently envisioned. |
| **Response:** While we understand this desire, the definition is a high-level description of CBM; the requirements contain all the details, and therefore, we don't believe that the definition should be expanded to include all this detail. | | | |
| Nova Scotia Power | | ☑ | CBM is required to meet Resource Adequacy Requirements. Generation Reliability implies that access to transmission makes generation (and generators) more reliable. Resource Adequacy ensures that firm load can be supplied to a level of reliability adopted by the RRO. The resources to meet those requirements include reserve margin provided by excess generation or interruptable load. If the "resource" is located across a posted path, then CBM provides access to the resource. Since "resource" can include generation and load, then the NERC definition is insufficient. |
| **Response:** See summary response. | | | |
| MEC<br>MRO | ☑ | ☑ | It would be better if CBM is defined in the NERC glossary as provided in the FERC Order 890 as meeting "Generation Reliability Criteria" however, the existing definition is adequate. |
| **Response:** See summary response. | | | |
| FirstEnergy | ☑ | | |
| SERC ATCWG | ☑ | | |
| Duke Energy | ☑ | | |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Entergy Services | ☑ | | |
| MEAG | ☑ | | |
| MEC Trading | ☑ | | |
| PSC of SC | ☑ | | |
| Southern Co Svcs | ☑ | | |

6. **In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.**

**Summary Consideration:** There was no consensus amongst the stakeholders who responded to this question. In the absence of a clear consensus, a queuing process has not been incorporated in the revised draft of the standard. This shall serve as a single response to all opinions offered in response to this question.

| **Question #6** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSC of SC | | | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| **Response:** Note that stakeholders do not need to respond to every question on the comment form. | | | |
| APPA | | ☑ | The needs to secure a transmission path to reach generation resources outside a LSE Balancing Authority Area that will "meet generation reliability requirements" are extremely important to reliable operations of the BES. Since the Reliability Standards are written to insure reliable operations a TSP would be hard pressed to deny an LSE the ability to secure resources to meet "generation reliability requirements." If a TSP denied this service it could be exposed to acts of non-compliance should the BES's integrity diminish because the TSP denied the LSE the CBM capacity. |
| Entergy Services | | ☑ | There is no need to have a queue process for CBM. Transmission Service Requests are approved if ATC is available and ATC is calculated using CBM. Therefore, CBM needs to be set aside first to accurately calculate ATC before Transmission Service Requests can be approved. |
| FirstEnergy | | ☑ | CBM is a reliability product that must be available when called upon. Transmission service requests are a business product that may have reliability impacts if properly scheduled. Any queing process would have to give priority to CBM. |
| IESO<br>IRC SRC | | ☑ | By virtue of the definition and formula of ATC determination, CBM is the component that must be allotted before any transmission service requests are assessed and granted. |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| ITC | | ☑ | Absolutely not. The original justification for CBM is that the transmission system was built for the contingencies envisioned by CBM. It was paid for by the original local network customers. No one should be allowed, by queuing process, to supercede this. However, if there is not sufficient transmission capacity to provide a CBM margin as well as requests for transmission service, the system should be expanded to provide the needed capacity. While there is a system impact process to cover this situation, it has |

| Question #6 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | not worked well in the last 10 years. Improved import capacity into a deficient system to meet all needs should be addressed in the planning process not some queuing process. |
| MEC<br>MRO | | ☑ | CBM is basic reliability requirement. If not met, transmission expansion planning should plan for it and should not sell addition transmission service on the same path/flowgate. |
| SERC ATCWG | | ☑ | We need more clarification on the queing process. What is the definition. |
| WECC MIC MIS ATC Task Force | ☑ | | The question is unclear at to whether it applied to an R4/R6 "request to set aside" or an R8 "request to schedule energy." A queuing should apply at the initial "request" stage (R4 and R6). Since by definition, CBM is a "firm" commitment, its request under R4/R6 would place it in the highest priority queue. If addressed there, no queuing problem exists in R8. Since the R8 "schedule" cannot take place until the RC declares an EE2 under R10; and whereas the R4/R6 set the priority, it would seem there would be no queuing issue even in emergency conditions. If this is not the case, the NERC Team should clarify how each of these "Rs" interplays sequentially.<br><br>R4. In R4 CBM is "requested" to comply with a regulatory mandate. This would include a body such as a state or local governance board in which case the LSE is at the mercy of the regulatory body.<br>R6. We read R6 as an alternative method for determining CBM "IF" the regulatory approach in R4 does not apply. (If that's not the case that should be clarified.)<br>R5. Either way, in R5 the approach and the details get documented and retained.<br>R7-R8. In R7 the TSP makes sure there is enough to go around in ***anticipation*** that the LSE can "schedule" it when needed under R8.<br><br>If the request for queuing is under R4, the LSE's request should have the absolute highest priority; otherwise, it could be forced into immediate noncompliance with it regulatory mandate. Since the requested amount under R4 or R6 is set aside as firm before R8 is triggered (with the condition precedent under R10), then under R8 queuing should not be a problem as the capability requested in R4 was already set aside in R7. Thus, if the question addresses R4 – "request" to "set aside" – than "yes" there should be a queue and the LSE should be first.<br>If the question addresses, R8 – "request" to "schedule" the question is actually moot as the capacity has already been set aside as firm by the TSP in R7 and queuing should simply be in accordance with the now applicable rules. Firm first… others next. |
| **Response:** Re your first comment: Assuming that all LSEs have submitted their request per section R4.2, there should be | | | |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| no need for queuing as long as the appropriate CBM was set aside in the first place.<br><br>Re: your 2nd comment: We believe all LSEs are "at the mercy" of those entities responsible for setting their resource adequacy requirements. I.e., you can't ask for more CBM then they would allow you to have via a CBM MW import requirement. If "there is not enough to go around," you need to go back to the responsible entities (the ones setting your rates) and request additional transmission to meet resource adequacy. If they don't agree, you don't have any justification.<br><br>Re: your 3rd comment: The last comment implies there shouldn't be a queuing process. If the LSE's request for CBM is of the highest priority, there is no queuing, they come first. We agree the LSE should come first and get all they ask for. | | | |
| Duke Energy | ☑ | | CBM requests should be addressed on a "first-come first-served" basis. LSE's are required to submit annual 10-year projections to the Transmission Service Provider. CBM requests will have lower priority than existing queued firm transmission service requests. NAESB should formalize the queuing process. |
| MEC Trading | ☑ | | This should be address in the TSPs OATT and filed at FERC. (Maybe it could be a requirement to just that in this standard) |
| **Response:** FERC has already stated that transmission rates must be adjusted to account for those that use or don't use CBM. | | | |
| Nova Scotia Power | ☑ | | There can easily be conflicts for multple LSE's requesting CBM, and there is a problem if the aggregate of all CBM requests exceeds the transmission capacity (R7). Therefore, if this is a new requirement, then there must be some "open season" to collect requests within a fixed time window similar to the Section 2.1 of FERC Order 888 pro-forma tariff. The CBM would be awarded to all comers if there is sufficient capacity but is allocated in lottery fashion if there are more requests than capacity. However, there is the question of the role of ETC in allocating CBM by this method. How much transmission capacity would be offered for CBM? I assume that existing Transmission Reservations cannot be impacted by the CBM bidding process, so only ATC for the planning horizon (if there is any) can be offered. What would an LSE pay for CBM. If it was required to pay the same as it would for a long-term (firm) reservation, then are they really getting CBM or are they getting a long-term firm Transmission Reservation). Some entities interpret Section 2.1 of Order 888 pro-forma tariff to permit bidding on amount and duration to award capacity to the "highest net present value" of the capacity. If there is no charge for CBM, how does the TSE recover lost transmission revenue? It seems that many of these questions must be directed to NAESB |
| **Response:** If the filed requests for CBM in section R4.2 exceed the transmission capacity available, it should be discovered at that point (re: your statement "aggregate of all CBM requests exceeds the transmission capacity"). It is important to note that R4 requests are based on recognized historic entities responsible for resource adequacy. If the system is not capable of handling these requirements (as would happen if there wasn't sufficient capacity to cover all "valid" CBM requests), then this entity should be consulted as to what to do. A queuing process will not result in someone meeting their resource adequacy | | | |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| responsibility. | | | |
| Southern Co Svcs | ☑ | | The request to reserve (set aside) a CBM amount by the LSE should be treated like any other firm transmission service request. |
| The STD disagrees. The LSE's request for CBM is of the highest priority, there is no queuing, and they come first. | | | |

**7. Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.**

**Summary Consideration:** There was no consensus amongst those who responded to this question to indicate support or rejection for the version of R3.3 in the first draft of the standard. Several commenters suggested that the impact of the generation import capability needs to be a consideration in CBM allocation and this was added to the revised requirements. Based on feedback in response to other questions in this comment form and feedback on other standards, the drafting team has also revised this section of the standard to make the determination of CBM a two-step process that aligns more closely with MOD-028, MOD-029, and MOD-030, while merging portions of R3 and R 7 into R4 of the revised standard. In the first step of the process the Transmission Service Provider analyzes how much of each request's CBM can be allocated, and in the second step the Transmission Service Provider sets CBM for a specific Posted Path or Flowgate. Here is the relevant revised portion of the standard – (note that in the revised standard the Load-Serving Entity that wants CBM must provide significant documentation to support the CBM request):

R4.1. Determine the amount of CBM (for use in R3.2) for each request by using one of the following:

R4.1.1. For the Area Interchange Methodology and the Rated System Path Methodology, using the requested Generation Capability Import Requirement for the Posted Path

R4.1.2. For the Flowgate Methodology, determining the significant impacts of each request on each Flowgate

4.1.2.1. Determine impacts of a request by multiplying the requested GCIR by the Distribution Factor for the transfer of that import from the specified Balancing Authority relative to the Flowgate.

4.1.2.2. Classify each impacts based on a Distribution Factor of 3% or greater as a significant impact.

R4.2. Set CBM for each Posted Path or Flowgate based on the sum of all requests such that all requests can be met simultaneously or all firm Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) has been allocated to CBM as follows:

R4.2.1. For Posted Paths, set the CBM for each Posted Path equal to the lesser of:

- The sum of all requests for Generation Capability Import Requirement for that Posted Path, minus the transfer capability set aside for reserve sharing for that Posted Path or
- The firm ATC for that Posted Path

R4.2.2. For Flowgates, set the CBM for each Flowgate equal to the lesser of:

- The sum of the significant impacts of all requests for GCIR for that Flowgate minus the impact of transfer capability set aside for reserve sharing for that Flowgate, or
- The firm AFC for that Flowgate

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSC of SC | | | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| **Response:** Note that stakeholders do not need to respond to every question on the comment form. | | | |
| MEC Trading | | | (Not sure if the Yes/No is for the first part of thequestion or the second) Network Response on path should be based upon network response by modeling it from the POR to the POD. |
| **Response:** Please see the revised standard. | | | |
| IESO | | | The way it is specified in R3.3 (and R3.2) is the correct approach. |
| **Response:** Please see the summary consideration. The drafting team made significant modifications to this requirement in support of stakeholder comments. | | | |
| APPA | | ☑ | The use of CBM capacity is just a reservation of transmission capacity that will only be used should an adverse situation develop in the BES and generation resources are needed to meet "generation reliability requirements." However, those generation resources are out side the LSE's Balancing Authority's Area. The simulation of energy over the CBM would be a study to determine how the system reacted under adverse operating conditions of the BES. How the use of CBM transmission capacity is treated will be determined how the final definition of CBM is written. Presently, both method would be needed because CBM is used for different purposes throughout the industry. |
| **Response:** In general, we agree with your observations. However, CBM should not be used for "different purposes." The intent of this standard is to specify what purposes CBM may be used for. | | | |
| Duke Energy | | ☑ | The standard should be flexible enough to allow the Transmission Service Provider to use either method which best supports reliability in their control area. |
| **Response:** Agree. The standard was revised to align more closely with the modifications made to MOD-028, MOD-029 and MOD-030. | | | |
| Entergy Services | | ☑ | CBM should be set aside on a path based on the response of CBM import MW level on that path. This should be treated similar to impact of loads or generation on paths by including their response on paths rather than algebraically subtracting from the path.. |
| **Response:** As revised, the standard requires consideration of the generation import capability in support of your suggestion. | | | |
| IRCSRC | | ☑ | CBM on path/flowgate should be the 'max' rather than 'sum' of all that's required to meet each individual LSE's resource adequacy requirement. Reasoning: Generation emergencies don't happen all at once. Reserve a 'sum' is beyond the 1-day-in-10-year criterion (or whatever criterion that's used by the region), and is not an efficient way of utilizing transmission capacity.. |
| **Response:** As revised, the standard requires consideration of the generation import capability before 'capping' the amount of CBM that can be allocated. | | | |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| ERCOT | ☑ | | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC comments. | | | |
| ITC | | ☑ | It should be based on the response of the network to the most likely sources. It is important that the availability of generation in the source area be considered when doing this. For example, assuming a source network with minimal reserves would be a poor assumption. This is an area that will ultimately require a very astute compliance monitor to determine compliance. |
| **Response:** This is not a NERC issue, but really a FERC or Market Monitor issue. From the NERC perspective, the TSP should base their analysis on the request made by the LSE. | | | |
| MEC<br>MRO | | ☑ | CBM on path/flowgate should be the 'max' rather than 'sum' of all that's required to meet each individual LSE's resource adequacy requirement. Reasoning: Generation emergencies don't happen all at once. Reserve a 'sum' is beyond the 1-day-in-10-year criterion (or whatever criterion that's used by the region), and is not an efficient way of utilizing transmission capacity. |
| **Response:** See response to IRC SRC above. | | | |
| Nova Scotia Power | ☑ | ☑ | It will depend on where the LSE is located in relation to the interface. For example, can an LSE request CBM to access reserve capacity two systems away? Let's say that there are there radially connected systems A is connected to B and C is is only connected to B. LSE#1 in A requests CBM through B to access capacity in C. LSE#2 requests access to capacity in A. In assigning import CBM on the A-B interface, LSE B must consider that the requirement for capacity reserve is due to a shortage in B or in C or to a lesser probability in B+C. |
| **Response:** It is the responsibility of the TSP to define in its procedure for requesting CBM any limitations on the Balancing Authorities from which generation supporting the GCIR may be supplied. | | | |
| FirstEnergy | ☑ | | The posted ATC for the CBM reserved path should have been based on the network response or contractual limit for that POR to POD, and thus subtracting CBM on that path is consistent with the ATC determination. |
| **Response:** See summary response. | | | |
| MEAG | ☑ | | The use of CBM capacity is for LSE under any potential emergency of generation deficiency. By modeling the CBM as the transaction from the POR to POD at the required CBM import MW level would treat the adverse operation as a normal condition and reduce the import TTC for the TSP. |
| **Response:** See summary response. | | | |
| Southern Co Svcs | ☑ | | For this method, a maximum TTC is calculated for each path, and the CBM set aside is decremented from that path to yield the remaining capacity available for Firm use. The network response for the CBM set aside (POR to POD) is considered and reflected in the TTC when it is calculated. To consider the network response of the CBM set aside for a second time would result in a lower value than the requested amount being decremented from the requested path. This could result in an over- |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | commitment for that path. |
| **Response:** See summary response. | | | |

8. **If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.**

**Summary Consideration:** Most stakeholders who responded to this question indicated that the standard should require that CBM be re-evaluated and possibly reduced, resulting in a change in ATC. The standard has been changed to incorporate the following sub-requirement for a monthly re-evaluation by the LSE of its request to reflect any changes in future CBM needs.

R3.2 At least every thirty-one days, update the request provided per R3.1 to reflect any changes that alter future needs for CBM or indicate that no change is needed.

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSC of SC | | | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| **Response:** Note that stakeholders do not need to respond to every question on the comment form. | | | |
| Southern Co Svcs | | ☑ | This could facilitate the opportunity for hording transmission capacity. The standard as drafted requires the LSE to request CBM as needed and maintain the proper documentation as required. |
| **Response:** It can't be hoarding if the CBM is reduced. Currently, many TSPs set aside CBM but fail to reduce it when LSE's make additional firm purchases, thus reducing their LOLE when CBM is not reduced. It is also conceivable that an LSE may not renew a purchase thus increasing their LOLE. In that instance, the CBM should be increased. A new requirement to that the LSE adjust CBM when their Generation Capability Import Requirement needs change would prevent hoarding. | | | |
| WECC MIC MIS ATC Task Force | ☑ | | CBM should be called on only after TRM has been utilized during 0-59 minutes. Rolling into 60+ minutes, CBM should be called on. That said, as the foundational emergency subsides there should be a statement in the standard to "unwind" the utilization of CBM. If, for example, an LSE had reserved 100 MW of CBM in accordance with R4 but when required to use that capacity under R8 could actually serve 60 MW by other means, then CBM should be reduced to 40 MW and ATC increased accordingly. |
| **Response:** This question was intended not to cover decrementing of CBM when scheduled, but decrementing of CBM when assumptions change regarding how much is needed. We don't believe the Firm ATC will change, as the "reserved" capacity for CBM will simply turn into "scheduled" energy flow. The Non-Firm ATC would decrease, as the CBM that could be sold as non-firm would decrease. | | | |
| APPA | ☑ | | Reducing the CBM because new generation is built in the LSE's Balancing Authority's Area would be a financial decision by the LSE. I do not believe this Standard has authority to mandate financial decisions. However if new reliability rules are passed that limit the amount of resources located outside the LSE's Balancing Authority's Area, which |

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | can be used to meet "generation reliability requirements" then this Standard has the obligation to lower the CBM to the predetermined about of transmission capacity used for CBM. |
| **Response:** You're correct in that this standard cannot mandate financial decisions. However, when new generation is built or external resources are purchased, it is the decision by the LSE to meet its resource adequacy requirements in a more stable way than dependence on CBM. At the same time, when an LSE does this, it no longer is entitled to the full CBM prior to this change in resource adequacy. | | | |
| Duke Energy | ☑ | | As resource mix changes, CBM would be re-evaluated on an annual basis with updated LSE requests for CBM. |
| **Response:** We agree that the resource adequacy requirements supporting CBM should be reevaluated every year. However this question is referring to resource decisions made between resource adequacy calculations. | | | |
| Entergy Services | ☑ | | CBM should be recalculated to determine accurate CBM requirements that should include meeting the generation requirement from any other transmission service or new generation. Any double counting of elements that impact CBM calculations should be avoided. |
| **Response:** Most stakeholders who responded to this question indicated agreement. | | | |
| FirstEnergy | ☑ | | In the case of new generation, the recalcuation periodicity would conceivably be infrequent. In the case of capacity-backed transmission service, the recalculation periodicity may be frequent, but is necessary to allow the markets to function properly. |
| **Response:** Most stakeholders who responded to this question indicated agreement. | | | |
| IESO | ☑ | | CBM is intended for having transmission capability to meet generation deficiency. If this deficiency can be met via other means, then the CBM allotted will no longer be required and could even be reduced to 0 if required. |
| **Response:** Most stakeholders who responded to this question indicated agreement. | | | |
| IRC SRC | ☑ | | CBM is intended for having transmission capability to meet generation deficiency. If this deficiency can be met via other means, then the CBM allotted will no longer be required. |
| **Response:** Most stakeholders who responded to this question indicated agreement. | | | |
| ERCOT | ☑ | | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC comments. | | | |
| ITC | ☑ | | This is a simple answer. You invite double counting if you don't reduce CBM when this happens. It amounts to hoarding. This is already a problem in our opinion. |
| **Response:** Most stakeholders who responded to this question indicated agreement. | | | |
| MEC Trading | ☑ | | It is to the benefits of all stakeholders if the use of transmission is optimized so CBM should be re-evaluated and possible reduced if CBM is met by other means. Maybe the TSPs OATT should be the right place for this information. |

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** The SDT agrees with your point one. However, the OATT doesn't need to be changed if the standard we're writing requires CBM to be adjusted when additional resources are acquired which reduce dependence on CBM. | | | |
| MEC<br>MRO | ☑ | | It is to the benefits of all stakeholders if the use of transmission is optimized so CBM should be re-evaluated and possible reduced if CBM is met by other means. |
| **Response:** We agree, and will have modified the standard to incorporate reviews and updates to CBM at appropriate time intervals. | | | |
| Nova Scotia Power | ☑ | | CBM requirements can change from year to year. For example, if the market responds to price signals and additional generation is built, there is no longer a need for the originally plannned CBM, which should be released to the market. The same is true for entities which are required to install renewable generation or demand-side management programs, which can free existing generation to provide Resource Adequacy without the need for CBM |
| **Response:** We agree that the resource adequacy requirements supporting CBM should be reevaluated at least every year. However this question is referring to resource decisions made between resource adequacy calculations. | | | |
| MEAG | ☑ | | |

**9. Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.**

**Summary Consideration:** R6 has been removed from the revised standard. There was no consensus amongst those who commented to support the retention of the ~~standard~~ requirement – the standard was revised assuming that the resource adequacy studies have taken place – the results of these studies must be documented to support the Generation Import Capability Requirement, but 'how' to conduct these studies is not addressed in the revised standard. This shall serve as a single response to all opinions offered. Note that there is another SAR under development to address resource adequacy assessments.

| Question #9 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The LSE is performing many functions of the other Functional Entities, which are described in the Functional Model. As stated in Question 3 the author has incorrectly assigned duties of many different Functional Entities to the LSE in R.6 and will create confusion between this Standard and other Standards that are written for the many different subjects covered in R.6. It is recommended this requirement be completely removed. |
| Entergy Services | | ☑ | Requirement R6 addresses resource adequacy requirement and it does not belong in the CBM standard. Requirement R5.2 covers identification of appropriate criteria used for resource adequacy studies that will identify need for CBM, if any. Probabilistic studies, if included in resource adequacy studies criteria shall be used and there is no need to include requirement R6 in this standard. |
| WECC MIC MIS ATC Task Force | ☑ | | As drafted, the standard appears to say there are two ways to establish the level of CBM required: 1) via regulatory mandate at R4 or 2) via probabilistic analysis at R6, assuming there is no regulatory mandate.<br><br>If that is not the intent of the two methods, than perhaps the more clarity on when the two methods would be used is in order. |
| IESO<br>IRC SRC | ☑ | ☑ | By and large, R6 describe the process and assumption requirements for resource adequacy assessment via which the CBM is determined. It is our interpretation that FERC requires the basis of this assessment be made known to support and demonstrate a fair and consistent approach is taken in determining the CBM value. That said, R6 could arguably be placed in a standard on resource adequacy assessment. If R6 is to stay, at the very least some of the subrequirements can be removed or combined (see Comments under Q2 for an example). |
| ERCOT | ☑ | ☑ | See IRC comments submitted by Charles Yeung. |
| ITC | ☑ | ☑ | How else would a compliance monitor be able to evaluate a justification for CBM if he |

| Question #9 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | doesn't have the input used to make such a determination. If anything, this could be expanded to assist the compliance monitor in such a determination. |
| MEC | ☑ | ☑ | I prefer if all CBM requests were supported by appropriate probabilistic based studies. It does seem odd that when the better approach (the probabilistic approach) is used, then the standard has all kinds of requirements defining how the better approach is to be done. |
| MRO | ☑ | ☑ | The MRO would prefer if all CBM requests were supported by appropriate probabilistic based studies. It does seem odd that when the better approach (the probabilistic approach) is used, then the standard has all kinds of requirements defining how the better approach is to be done. |
| Nova Scotia Power | ☑ | | There should be a high level of proof that CBM is required. An important component is the ability to deliver this energy with single contingencies. |
| Duke Energy | ☑ | | |
| FirstEnergy | ☑ | | |
| MEC Trading | ☑ | | |
| PSC of SC | ☑ | | |

**10. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.**

**Summary Consideration:** Some entities may desire to pursue regional differences based on their current practice or tariff. We agree there may be commercially sensitive information in the CBM process, and have removed all public posting requirements from this standard and have requested that NAESB address the requirements related to "public posting." We have modified the timings in the standard to allow for processing of requests in a reasonable amount of time.

| Question #10 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | ☑ | | As noted above. |
| **Response:** Please see response above. | | | |
| ERCOT | ☑ | | ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area Interconnection and there has been no reservation of transmission capacity in ERCOT.<br><br>Capacity Benefit Margin is defined as the amount of firm transmission transfer capability preserved by the transmission provider for Load- Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.<br><br>Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. In the |

| Question #10 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | current and future ERCOT market design the use of CBM is not applicable to the ERCOT Interconnection. ERCOT does not have a synchronous connection with any other Control Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance. |
| **Response:** The SDT agrees this is a concern - ERCOT may wish to pursue a request for a Regional Difference.. | | | |
| MEC Trading | ☑ | | FERC Order 890 required consistency and this standard does not require any consistency. |
| **Response:** The consistency is achieved by requiring an LSE to prove that they have supportable resource adequacy requirements that allow for the use of CBM. By law, the ERO cannot set resource adequacy standards but can require an LSE to demonstrate that they have supportable requirements that do provide for CBM to meet these requirements. We expect consistency within the domain of the local entity responsible for resource adequacy (by state, by region, etc). | | | |
| Nova Scotia Power | ☑ | | R2 requires documentation to be "publicly released" (published on OASIS) information that is either commercially sensitive or can include Critical Infrastructure Information, the wording of R8 in MOD-008 should be used in MOD-004 to protect information. The process of taking bids on CBM will require modifications to transmission Tariffs and Market Rules may have to be updated to reflect the new requirements. |
| **Response:** We have changed R2 so that it no longer includes the phrase, 'make publicly available,' and expect that NAESB will address release of information to customers. Note that in the revised standard, the Transmission Service Provider must share the models it uses to allocate CBM with various reliability entities in R7 of the revised standard.<br><br>We don't expect tariff changes for CBM. See responses to question 6 regarding queuing. | | | |
| Southern Co Svcs | ☑ | | R7 requires the Transmission Service Provider to answer a request for CBM within 30 days of receipt. This is inconsistent with the time allowed to answer other firm transmission service requests per Tariff and should be revised to track the tariff requirements for processing long term firm transmission requests. |
| **Response:** The revised draft of the standard requires the TSP to respond in 14 days to requests for monthly values in the current and subsequent year, because the LSE is required to update the request every 31 days. (See R3 in the revised standard.) The time for response to requests for yearly values beyond that time period has been extended to 60 days. (See R4 in the revised standard.) | | | |
| ITC | | ☑ | R4 gives the LSE great latitude in defining their resource adequacy requirements. R4 allows the LSE to fully document whatever requirement they have. It will ultimately be |

| Question #10 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | up to the compliance monitor to evaluated their justification and documentation. |
| **Response:** The SDT agrees with this comment. | | | |
| IESO<br>IRC SRC | | ☑ | However, there are entities that do not provide physical transmission services. Hence, these standards or some of the requirements in these standards may not apply. |
| **Response:** FERC has indicated that the TSP must offer CBM to its LSEs, and as such, the standard requires all TSPs to prepare and maintain CBM procedures. Requirement 1 applies regardless of whether or not you provide physical transmission service, but allows for the TSP to specify the details of how they have elected to implement CBM. All other requirements are dependent upon a requested need for or use of CBM, and may not apply if CBM is not used in the region. | | | |
| WECC MIC MIS ATC Task Force | | ☑ | |
| Duke Energy | | ☑ | |
| Entergy Services | | ☑ | |
| FirstEnergy | | ☑ | |
| MEC | | ☑ | |
| MRO | | ☑ | |
| PSC of SC | | ☑ | |

11. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1. Comments:**

**Summary Consideration:** Several commenters provided suggestions for improvement, which have been incorporated into the new standard. The drafting team notes that this question incorrectly referred to MOD-001, and apologizes for any confusion this may have caused. Please see the cover page of this report for a complete list of requirements modified in response to stakeholder comments.

| **Question #11** | |
|---|---|
| **Commenter** | **Comment** |
| WECC MIC MIS ATC Task Force | **A.** R3. Each of the sub-bullets contains the term "reserve sharing" (R.3.1.2; R.3.2.1; R.3.3.1). This is not used as a defined term in the standards; however, Reserve Sharing Groups is a NERC defined term and may more accurately address what the standard is seeking to address.<br>Suggested rewrite:<br>(E.g.) R3.2. The Transmission Service Provider that uses the Rated System Path…<br>R3.2.1. The Transmission Service provider shall not include in the CBM calculation any transmission capacity set aside as part of a Reserve Sharing Group agreement already accounted for in the TRM calculation.<br>**B.** R4. We suggest the second parenthetical phrase be deleted as it does not add any significant clarification.<br>**C.** R6.3.1. Designated Network Resource (DNR) is used as a defined term without a NERC Glossary definition. The Team suggests using language from Section 1.26 "Network Resource" within the Pro Forma OATT as a springboard for a new definition.<br>**D.** R6.4. - Intent is unclear.<br>R6.4 Suggested rewrite: "Identify all resources in the Load-Serving Entity's ***Balancing Authority Area*** excluded from serving the Load-Serving Entity's load, including: " (Emphasis and language added)<br>**E.** R8 is unclear.<br>If CBM is "reduced" in R7.2 what does it mean that the LSE is "still entitled to the CBM MW import?" Please clarify or rewrite. |
| **Response:**<br>A. R3 **-** Re: Reserve sharing – the term 'reserve sharing' is not defined and has a meaning that is well understood so the team did not define the term. Drafting teams have been asked to avoid defining terms that have a commonly understood meaning.<br>B. R4 – Re elimination of second parenthetical – the drafting team adopted this suggestion and revised the entire requirement so it is simpler to read.<br>**C.** The term "Designated Network Resource" has been removed.<br>D. Requirement 6 was deleted from the revised standard. The revised standard assumes that the studies have been completed and requires that there be documentation to support the studies, but the revised standard does not detail 'how' to perform the studies.<br>E. R8 was confusing and has been deleted. The revised standard includes much clearer requirements for the allocation of CBM and requires | |

| Question #11 | |
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| **Commenter** | **Comment** |
| that the Load-Serving Entity update its request for CBM at least once/31 days. | |
| WECC MIC MIS ATC Task Force | **F.** Order 890, P. 262 states:<br>"…we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards…process." (Emphasis added.)<br>"We direct public utilities…to specify the generation deficiency conditions during which an LSE will be allowed to use…CBM." (Emphasis added.)<br>R10. states,<br>"The Load-Serving Entity shall declare a NERC Energy Emergency Alert (EEA) 2 and initiate all steps in EEA 2 prior to scheduling of energy over transmission capacity set aside as CBM." (Emphasis added.)<br>EOP-002, states:<br>"A. General Requirements<br>**1.** Initiation by Reliability Coordinator. An Energy Emergency Alert may be initiated *only by a Reliability Coordinator* at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity." (Emphasis added.)<br>In contravention to Order 890, P. 262, R10 as drafted *does not state the specific "generation deficiency conditions" required as a condition precedent for an LSE to call upon CBM*.<br>In contravention to EOP-002, R10 grants an LSE the right to declare a NERC Energy Emergency 2. The NERC Drafting Team needs to remedy the conflict.<br>Suggested language:<br>*(Plagiarized from Attachment 1-EOP-002-0; Energy Emergency Alerts)*<br>RX.1. Each Load-Serving Entity that is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or that cannot schedule known resources due to insufficient transmission capacity, shall instruct its Reliability Coordinator to declare an Energy Emergency 2.<br>RX.2. Each Load-Serving Entity shall instruct its Reliability Coordinator to declare a NERC Energy Emergency 2 prior to scheduling any energy on transmission capacity reserved for CBM.<br>R.X3. Each Reliability Coordinator instructed by a Load-Serving Entity to declare a NERC Energy Emergency 2 pursuant to this Standard, shall:<br>• Initiate a NERC Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."<br>• Act to mitigate the emergency condition, including a request for emergency assistance if<br>• Required |
| **Response:** The drafting team revised the language in R10 rather than propose modifications to EOP-002. As revised, R10 requires the Transmission Service Provider to only approve Interchange Transaction Tags using CBM if the deficient entity is under an EEA | |

| Question #11 | |
|---|---|
| **Commenter** | **Comment** |
| 2 and CBM is available. This supports your suggestion to clarify that it is not the Load-serving entity that declares the EEA. | |
| WECC MIC MIS ATC Task Force | **G.** R11. The report required in R11 should also be mandated for delivery to the Balancing Authority and the Reliability Coordinator for purposes of post mortem examination.<br><br>R11. Change "declared" to "instructed."<br>**H**. R1.1. Should be changed to read: "Its procedure for a Load-Serving Entity to request its CBM import MW requirement on each REQUESTED Point of Receipt – Point of Delivery (POR-POD) combination or POSTED PATH…." (Emphasis Added.)<br>Orders 889/890 do not require posting of information on every possible combination of POR/POD nor on every possible path. Thus information must only be posted on "Posted Paths."<br>The defined term "Posted Path" must be added to the NERC Glossary to meet the intent of Orders 889 and 890 without creating an onerous burden to post information need by no one. It was not FERC's intent to require the posting of ATC / TTC et al for paths upon which there is no request for service.<br>The following Posted Path definition must be added to the NERC Glossary and utilized in each of the ATC related standards:<br>Posted Path<br>Posted Path means: 1) any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.<br>Although the WECC Team has only addressed the definition of a Posted Path, we would encourage the NERC ATC to develop a parallel definition to properly delimit the Flowgates upon which information must be posted, as clearly, FERC did not intend that information be posted on each and every Flowgate or path simply because a Flowgate or path exists. FERC's intent as to what paths and Flowgates were affected by posting was clearly laid out in Order 889 as well as 890 per the aforementioned references. |
| **Response:** The requirement has been removed. The post mortem examination is the responsibility of the compliance monitor and if needed can be added to the standard as a type of 'exception reporting'. | |
| WECC MIC MIS ATC Task Force | **I.** R1.2 Should read, "…over each POSTED PATH or Flowgate."<br>**J.** R1.4 Should read, "…for each timeframe by Flowgate or POSTED PATH, as applicable." (Emphasis Added.)<br>**K.** R2. Should read, "…over each POSTED PATH or Flowgate…"<br>**L.** R3.2 Should read, "…for determining Total Transfer Capability shall use the algebraic sum of all valid CBM requests for each POSTED PATH as the CBM for that path." (Emphasis Added.)<br>**M.** R4.2. Should read, "…for each POSTED PATH or specified POR-POD combination for each year…" Again, a parallel definition to POSTED PATH for affected Flowgates would be of value here. This Team did not pursue |

| Question #11 | |
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| **Commenter** | **Comment** |
| | such a definition but encourages the NERC ATC Drafting Team to do so.<br>**N.** R5.1 Same comment as above at R4.2.<br>**O.** R6. Same comment as above at R4.2.<br>**P.** R7. And R7.2. Same comment as above at R4.2.<br>**Q.** R7.3 uses the term Import Entitlement without supplying a definition.<br>**R.** R8.1 Same comment as above at R4.2.<br>**S.** R13. Same comment as above at R4.2.<br>**T.** The WECC Team suggests the following clarifying language bee added to R8.<br><br>"R8. The Load-Serving Entity may request the scheduling of energy *FOR ANY TIME HORIZON* over transmission capacity set aside as CBM up to an amount equal to that determined under R7 as required by the Transmission Service Provider's procedure pursuant to R1.3. (Emphasis added.)<br><br>R1 and R2 of MOD-004-1 should be clarified to show that CBM procedures and copies of the models used for allocating CBM over paths need only be made public "if" CBM is included in the TSP's overall ATC calculation. |
| **Response:**<br>I through P, R, S. We have incorporated the suggestion to define and use the term, 'Posted Path' in any of the identified requirements that were not retired or otherwise rephrased so they no longer need the term.<br>Q – R7 has been absorbed in R4 in the revised standard. The revised standard does not use the term, 'Import Entitlement' so no definition was added.<br>T – Allowing a Load-Serving Entity to schedule energy *FOR ANY TIME HORIZON* over transmission capacity set aside as CBM up to an amount equal to that determined under R7 as required by the Transmission Service Provider's procedure pursuant to R1.3 does not support the definition of CBM which indicates that CBM is only to be used for emergency generation deficiencies. CBM should only be "scheduled" when it's needed during an EEA2 event. For any time horizon beyond EEA2 events, a transmission reservation would be required.<br>U - All public posting requirements will be addressed by NAESB, however, FERC has indicated that the TSP must offer CBM to its LSEs, and as such, the standard requires all TSPs to prepare and maintain CBM procedures | |
| BPA | R1. through R9. and R13. should be clarified that CBM need only be posted and requested on Posted Paths, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. |
| **Response:** We agree. The entire set of standards was modified to adopt the use of the term, "Posted Path" as suggested by BPA and several other entities. | |
| Duke Energy | R3.1.1 - Existing Transmission Commitments (ETC) is not included in definitions, but it should be defined. |
| **Response:** We agree, and have written a definition for the Glossary in MOD-001. | |

<table>
<tr><th colspan="2">Question #11</th></tr>
<tr><th>Commenter</th><th>Comment</th></tr>
<tr><td>Entergy Services</td><td>Entergy does not understand asking for comments on standard MOD-001-1 in this questionaire.<br><br>Requirement R8.1 should include a condition by appending the language " if other entities who reserved CBM on that path are not using their share of CBM. Under no circumstances, the total use of CBM by all entities on a path at any time will exceed the total amount of CBM reserved on that path and for that period."<br><br>Definitions of terms on page 2 do not belong in this standard and should be removed.<br><br>Entergy does not use CBM in their ATC/AFC calculations. It appears from the standard that it is mandatory for Transmission Service Providers to use CBM. It should be left to the descretion of Tansmission Service Provider to use CBM and its use should not be made mandatory.</td></tr>
<tr><td colspan="2">Response: Regarding MOD-001, this was a typographical error.<br><br>The standard was revised and has a new requirement (R10) that clarifies that the Transmission Service Provider can only approve Interchange Transaction Tags using CBM if the deficient entity is under an EEA 2 and CBM is available. This supports your suggestion for modifying R8.1.<br><br>The drafting team is allowed to submit definitions on any of the standards it submits. Since they all end up in the glossary, it is unimportant which standard to which they are attached. However, to aid in clarity, we will submit these definitions as part of MOD-001 the next time we make a posting.<br><br>Regarding the TSP electing to not offer CBM, we believe that FERC is requiring this in Order 693, paragraph 1082:<br>(1) clarify that CBM shall be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria; (2) develop requirements regarding transparency of the generation planning studies used to determine CBM value; (3) modify the current Requirements to make clear the process for how CBM is allocated across transmission paths or flowgates; (3) modify its standard in order to prevent setting aside CBM and TRM for the same purposes; (4) modify the standard by adding LSE as an applicable entity and (5) coordinate with NAESB business practice standards.</td></tr>
<tr><td>FIrstEnergy</td><td>1. R2 requires copies of models used for CBM allocation, but the allocations are not required to be and may not be based on power flow modeling.<br><br>In addition, it requires a request from an entity with a valid need. Methods are needed to determine what constitutes a valid need, who decides the validity of the need, and for resolving disputes.<br><br>2. R4.2 requires the LSE to allocate the CBM by path; however, the LSE may not have/use power flow tools consequently they may have difficulty complying with this requirement. The standard should include a method for managing offsetting resource requirements where the TSP has multiple</td></tr>
</table>

| Question #11 | |
|---|---|
| **Commenter** | **Comment** |
| | LSEs such as the situation where LSE A provides needed energy to LSE B without requiring an import. Under this scenario too much CBM may be set aside as the standard is currently written. R7.1 appears to attempt to cover this situation but it is not clearly stated and the basis for managing this is not addressed.<br><br>3. R13 states the TP "shall include all valid requests and projected CBM import MW requirements ... in its planning process." However, a method for needs to be established for managing situations where the import limitation is outside his area of responsibility. Overall, there are many good things in here.<br><br>4. R12 requires the TSP to make publicly available the report prepared by the LSE pursuant to R11. This requirement should be placed on the LSE that created and owns the report and has the retention responsibility.<br><br>5. To reduce confusion R14 should list the components of uncertainty rather than refering to MOD-008-1 R1.1. This MOD-008-1 requirment requires TPs and TOPs to include these elements in the TRM analysis where MOD-004-1 requires the LSE to exclude these values from the CBM calculation. The difference in application may be lost in switching back and forth between the two standard's requirements. |

**Response:**

1. The standard drafting team modified the requirement as follows to eliminate the need to make the model publicly available and to allow for information other than models to be provided.

> The Transmission Service Provider and Transmission Planner shall each provide copies of the supporting data, including any models, used for allocating CBM over each Posted Path or Flowgate to the following:
>
> > Each of its associated Transmission Operators within seven calendar days of a modification to the CBM.

2. The standard is placing a responsibility on the LSE to document and provide data to support the justification of CBM. Beyond the LSE, it is expected that TSPs will have to upgrade their methods and systems in order to comply with this standard. This standard does place new obligations on several entities that may require time, money and manpower to comply.

3. CBM is only set aside on the facilities of the TSP in which the load is located. Accordingly, the TSP may not address import limitations outside their area of responsibility, consistent with their other planning processes.

4. We have eliminated this requirement and have requested that it NAESB address this and all other public posting requirements as business practices.

5. We intended to reduce confusion by referring the list in only one place, rather than create a potential for the lists to get

**Question #11**

| Commenter | Comment |
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| out of synchronization as standards change. R14 was removed and the standard for TRM (MOD-008) includes a requirement to ensure that the same components of uncertainty are not used for both CBM and TRM. (See R2 in the revised MOD-008.) removed | |
| IESO<br>IRC SRC | ETC is introduced in this standard for the first time and hence this term needs to be defined here. |
| **Response:** We have written a definition for ETC, and have included it with the revised draft of MOD-001. | |
| ERCOT | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC comments. | |
| ITC | (note question 11 should have referred to MOD-004 not MOD-001) While compliance has not been addressed, it is worth noting that the compliance monitor for CBM requirements will have to be a very astute individual or group to deal with the multiple possible resource adequacy requirements under the ERO. They will no doubt have to deal with non-jurisdictional entities to make their evaluations. We suspect it will be a lengthy process in some cases. We would also like to point out that the TSP has little latitude in using the MW import requirement supplied by the LSE. If they suspect that this value is too high, they don't have recourse here to do anything about it. Even if a large fine could result from a compliance issue, the TSP must sell service with a margin they may have good reason to feel is unjustified. Is a large fine justification enough to not give the TSP some latitute? |
| **Response:** There was a typographical error in the question and it should have referenced MOD-004 rather than MOD-001. We recognize that compliance may be challenging. The drafting team modified the standard so that the requirements that focused on conducting resource adequacy studies have been removed – the revised standard is written assuming that the studies have been conducted – and the revised standard requires that the results of the studies be documented. | |
| MEC Trading | The purpose of each of the standards should be revised to be more in-line with the other ATC/TTC/TRM stanadards. We recommend that the purpose in this standard be revised to state: "To promote the consistent and transparent…use of Capacity Benefit Margin (CBM) for reliable system operation." The standard should make it clear that an LSE should be required to do comply with certain requirements within this standard only if it requests CBM. Also this industry is sophisticated enough to perform or have performed a probabilistic study so that it what the CBM should be based on. |
| **Response:** We revised the purpose in support of your suggestion.<br>The standard drafting team has attempted to address the second comment in the requirements by limiting the scope of the requirement. The revised standard's R3 states, 'A LSE with that wants transfer capability set aside in the form of CBM shall:"<br>The standard was revised so that the requirement for probabilistic studies (R6) has been removed – the revised standard's requirements are written assuming that these studies have been conducted, and the revised standard requires that the results of the studies be documented | |
| MEC | The purpose of each of the standards should be revised to be more in-line with the other ATC/TTC/TRM stanadards. |

| Question #11 | |
|---|---|
| **Commenter** | **Comment** |
| MRO | The purpose in this standard be revised to state: "To promote the consistent and transparent…use of Capacity Benefit Margin (CBM) for reliable system operation." |
| **Response:** We revised the purpose in support of your suggestion. | |
| Manitoba Hydro | MH is not a supporter of the use of CBM as we believe that CBM makes the unsupportable assumption that there will be energy and transmission avaialable in the adjoining entitity during the time of the emergency. However as there a desire to maintain this feature, MH believes that there should be a requirement to build if CBM causes the AFC on a flowgate to become negative and that a portion of cost should be assigned to the LSE who is responsible for the CBM. |
| **Response:** The CBM needs to be considered in the annual evaluation of network service that TOs are supposed to make. If the transmission system in question cannot support the requested CBM, then a system impact study should commence. i.e., if you use CBM, then you should plan for it. NERC does not have the authority to require entities to 'build' transmission or generation facilities. | |
| Nova Scotia Power | The standard does not address the issue of export transmission capacity, since CBM is an import capacity only. An interface involves at least two TSP's: the TSP owning the export side and the TDP owning the import side. Has the drafting team examined the issues around a LSE that requests CBM held back from import but the export TDP can accept reservations without consideration to CBM. Say that the ATC on A-B interface is 200 MW. An LSE in B requires 50 MW of CBM which reduces import ATC on the B side to 150 MW and ATC on the A side remains at 200 MW. A transmission customer in B requests firm reservations on the A-B interface of 200 MW. The A TSP assigns 200 MW to the customer and the B TSP says he can only have 150 MW. The customer takes all 200 MW on the A side but nothing on the B side. Does he then effectively block A-B transactions?. |
| **Response:** This is an important point that is not being addressed. The assumption is that interconnections with neighbors are shared and were constructed, in most cases, to insure access to external resources to meet resource adequacy requirements. This was a mutual benefit. Both sides have access to external resources. An import problem to one is an export problem to the other. If one side has had "historical" access to external resources to meet their resource adequacy requirements, can the other side now complain that it impedes their "export" capability? This may be debatable but CBM has been a recognized margin for at least the 11 years since US deregulation. That's why it's important that any CBM claim be both documentable and supportable by whoever is responsible for the resource adequacy requirements of the LSE. | |

**12. In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.**

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)? Reply:

**Summary Consideration:** The drafting team thanks all who provided responses. This shall serve as the summary response to all information provided.

| Question #12 | |
|---|---|
| **Commenter** | **Yes**<br>**No**<br>**Comment** |
| APPA | It is not within the scope of this SDT to deal with resource studies, in fact the glossary states the Resource Planner determines the resource adequacy. Generation Reserves has not been defined in the standards nor has Resource Adequacy. |
| BPA | For Generation Reserve and Resource Adequacy requirements, BPA follows the procedures developed by the Northwest Power Pool which meet the WECC's Minimum Operating Reliability Criteria. BPA also meets the requirements in the NERC standards for Control Performance BAL-001-0 and Disturbance Control BAL-002-0. |
| Duke Energy | The NC and SC state commissions exercise their authority in this area by requiring an annual filing by the regulated utilities, which includes the identification and justification of reserve margins. |
| ERCOT | Within ERCOT, a technical recommendation is developed by ERCOT System Planning, acting as the Planning Coordinator. ERCOT Market Participants can give input to the process through open meetings. The technical recommendation is subject to approval by the ERCOT Board of Directors and the Public Utilities Commission of Texas (PUCT). The technical recommendation stipuates generation reserve and resource adequacy requirements both for long term planning and for operating reserve. |
| FirstEnergy | The Regional Reliability Organization - ReliabilityFirst |
| IESO | In Ontario, it would be the IESO and the Ontario Power Authority (OPA) which would be responsible for establishing generation reserve and resource adequacy requirements. |
| IRC SRC | Unable to provide a specific answer as a group. Gernally speaking, however, it is the region that |

| **Question #12** | |
|---|---|
| **Commenter** | **Yes**<br>**No**<br>**Comment** |
| | stipuates generation reserve and resource adequacy requirements both for long term planning as well as for operating reserve. (SRC please note: I'm only speculating. Don't let me put words in your mouth) |
| ITC | TC does not have a resource adequacy requirement. We must work with the LSEs in our service territory to determine appropriate CBM to plan for. These requirements allow for this to happen. |
| MEC | It is my understanding of the 2005 Energy Policy Act that the Regional Reliability Organization or NERC can either set the generation reliability criteria or enforce the generation reliability criteria, but it cannot do both. The MRO is in the process of proposing to set the generation reliability criteria as 1 day in 10 years. It will be the responsibility of the Load Serving Entity or its delegate (such as a Planning Reserve Sharing Group) within the MRO to set the reserve margin to meet the 1 day in 10 year criteria. The State will enforce the generation reliability criteria and the Planning Reserve Sharing Group will enforce the reserve margin requirement. |
| MRO | It is the MRO's understanding of the 2005 Energy Policy Act that the Regional Reliability Organization or NERC can either set the generation reliability critiera or enforce the generation reliability criteria, but it cannot do both. The MRO is in the process of proposing to set the generation reliability criteria as 1 day in 10 years. It will be the responsibility of the Load Serving Enetity or its delegate (such as a Planning Reserve Sharing Group) within the MRO to set the reserve margin to meet the 1 day in 10 year criteria. The State will enforce the generation reliability criteria and the Planning Reserve Sharing Group will enforce the reserve margin requirement. |
| Nova Scotia Power | NPCC sets LOLE standards. |
| PSC of SC | PSCSC reviews reserve margin / resource adequacy of regulated electric utilities in Integrated Resource Plans. |
| Salt River Project | SRP sets its Generation Reserve and Resource Adequacy requirements in accordance with WECC Standards. |

**13. With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:**

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource. Reply:

**Summary Consideration:** The drafting team thanks all who provided responses. This shall serve as the summary response to all information provided.

| **Question #13** | |
|---|---|
| **Commenter** | |
| APPA | It is not within the scope of this SDT to deal with resource studies, in fact the glossary states the Resource Planner determines the resource adequacy. LOLE and LOLP are methods used by the Resource Planners. |
| Duke Energy | None |
| ERCOT | CBM is not used within ERCOT, |
| FirstEnergy | Currently the ISO determines CBM via an LOLE study based on 1/10 of a day/year. Currently Ohio does not have a requirement for an LOLP. ReliabilityFirst has established a 1 day in 10 year LOLP criteria that is voluntary. In the future, the ISO PRSG may self-contract an LOLP enforcement requirement. It is expected that the ISO market rules will eventually enforce LOLP. |
| IESO | The IESO uses stochastic tools like GE MARS to establish reserve requirements for meeting loss of load expectations (LOLE). However, for Ontario, the concept of CBM is not used and is set to 0. |
| ISO SRC | Unable to provide a specific answer as a group. Again, the LOLE approach is rather commonly used by the ISOs and RTOs in assessing resource adequacy. (SRC please note: ditto the above) |
| ITC | ITC does not have a requirement, although we are familiar with the LOLE/LOLP evaluations. We strongly believe that R6 is a must for this standard. We have heard estimates that as much as 90% of the load in this country is subject to LOLE requirements based on LOLP studies. To not have requirements in this area would be negligent. |
| MEC Trading | LOLE study |
| MEC | I would prefer an LOLE study requirement to support the CBM requests of the Load Serving Entities. |
| MRO | MRO would prefer an LOLE study requirement to support the CBM requests of the Load Serving Entities. |

| Question #13 | |
|---|---|
| Commenter | |
| Nova Scotia Power | LOLE simulations with assumed transmission capacity, however the answer is around 20% reserve |
| PSC of SC | Our comments are from a regulatory perspective. This is strictly a technical issue. |
| Southern Co Svcs | Addressing these concerns should be the role of the resource adequacy drafting team and should be handled in the resource adequacy standard. |
| Salt River Project | SRP's current planning reserve target is based on historical study work that considered unit availability, load uncertainty, and projected costs associated with carrying different levels of reserves. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a standard drafting team on March 17, 2006.
4. SDT posted first draft for comment from February 15–March 16, 2007.

**Description of Current Draft:**

This is the second draft of the proposed standard posted for stakeholder comments. This draft represents consideration of stakeholder comments submitted with the first draft of the proposed revisions to MOD-001 as well as consideration of applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Respond to comments. | TBD |
| 2. Post revised standard for stakeholder comment. | TBD |
| 3. Respond to comments. | TBD |
| 4. Post for 30-day pre-ballot review. | TBD |
| 5. First ballot of standard. | TBD |
| 6. Respond to comments. | TBD |
| 7. Recirculation ballot. | TBD |
| 8. 30-day posting before board adoption. | TBD |
| 9. Board adoption. | TBD |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title:** **Available Transfer Capability**
2. **Number:** MOD-001-1
3. **Purpose:** To promote the consistent and uniform application and documentation of Available Transfer Capability (ATC) calculations for reliable system operations.
4. **Applicability:**
   **4.1.** Planning Coordinator.
   **4.2.** Reliability Coordinator.
   **4.3.** Transmission Service Provider.
5. **Proposed Effective Date:** To be determined.

## B. Requirements

**R1.** Each Transmission Service Provider, and its associated Planning Coordinators and Reliability Coordinators, shall agree upon and implement one or more of the ATC methodologies specified in Reliability Standard MOD-028, MOD-029, and MOD-030 for use in determining Transfer Capabilities of those Facilities under the tariff administration of that Transmission Service Provider.

**R2.** Each Transmission Service Provider, and its associated Planning Coordinators and Reliability Coordinators, shall apply the agreed upon ATC methodology or methodologies to calculate values for all ATC time horizons listed below:

**R2.1.** Scheduling horizon (same day and real-time).

**R2.2.** Operating horizon (day ahead and pre-schedule).

**R2.3.** Planning horizon (beyond the operating horizon).

**R3.** Each Transmission Service Provider shall make publicly available an "Available Transfer Capability Implementation Document" (ATCID) that includes, as a minimum, the following information:

**R3.1.** Information describing which methodology (or methodologies) has been selected and how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC calculations may be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counter-flows.

**R3.3.** The identity of the Planning Coordinator and Reliability Coordinator associated with each Facility under the Transmission Service Provider's tariff.

**R3.4.** The identity of the Transmission Service Providers to which it provides data for use in calculating transfer capability.

**R3.5.** The identity of the Transmission Service Providers from which it receives data for use in calculating transfer capability.

**R4.** The Transmission Service Provider shall notify the following entities (via electronic mail) a minimum of 14 calendar days before implementing a new or revised ATCID:

**R4.1.** Each Transmission Planner in the Transmission Service Provider's area.

**R4.2.** Each Planning Coordinator in the Transmission Service Provider's area.

**R4.3.** Each Reliability Coordinator in the Transmission Service Provider's area.

**R4.4.** Each Transmission Operator in the Transmission Service Provider's area.

**R4.5.** Each Planning Coordinator adjacent to the Transmission Service Provider's area.

**R4.6.** Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

**R4.7.** Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

**R4.8.** Each party that has previously requested to be notified of such actions.

**R5.** Each Transmission Service Provider that calculates ATC shall, at a minimum, recalculate ATC at the following frequency:

**R5.1.** For hourly ATC, once per hour, (on the hour), for the next 168 hours.

**R5.2.** For daily ATC, once per day, (at midnight prevailing time the day previous), for thirty days.

**R5.3.** For weekly ATC, once per day, (at midnight prevailing time on the Monday previous), for four weeks.

**R5.4.** For monthly ATC, once per month, (at midnight prevailing time on the first day of the month previous) for 13 months.

**R6.** Each Transmission Service Provider shall make the following information available to any requesting Transmission Service Provider, Planning Coordinator, Transmission Planner, Reliability Coordinator, Transmission Operator, or other party with a demonstrated reliability need (subject to security and confidentiality requirements):

**R6.1.** Load forecasts.

**R6.2.** Generation dispatch, in the form of dispatch order, participation factors, or block dispatch.

**R6.3.** Planned and unplanned transmission outages.

**R6.4.** Planned and unplanned generation outages.

**R6.5.** Transmission Reservations.

**R6.6.** Power flow models.

**R6.7.** Facility Ratings.

**R6.8.** ATC recalculation frequency and times.

**R6.9.** Transmission Reservation impact modeling identification, such that a source-to-sink analysis of power flow impacts could be undertaken.

## C. Compliance

To be added with next posting.

## D. Measures

To be added with next posting.

## E. Regional Differences

None identified.

## F. Associated Documents

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
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| | ☐ | 4 — Transmission-dependent Utilities |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability. The proposed version of MOD-001 is an “umbrella” standard and it contains the general requirements applicable to ATC without regards to any particular methodology.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-001-1 ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the ‘White Paper’ and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with “ATC Standard” in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☐ No

   Comments:

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☐ Yes

☐ No

Comments:

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments:

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<table>
<tr><th colspan="3">Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name: E. Nick Henery</td></tr>
<tr><td colspan="3">Organization: APPA</td></tr>
<tr><td colspan="3">Telephone: 202-467-2985</td></tr>
<tr><td colspan="3">E-mail: nhenery@APPAnet.org</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☐ NPCC<br>☐ RFC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☒ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
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<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

**Group Name:** APPA

**Lead Contact:** **E. Nick Henery**

**Contact Organization:** **APPA**

**Contact Segment:** **Segment 1**

**Contact Telephone:** **202-467-2985**

**Contact E-mail:** **nhenery@APPAnet.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Matt Schull | North Carolina Municipal Power Agency #1 | **SERC** | Segment 5 - Electric Generators |
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   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The MOD-001 Standard incorrectly assigns duties to the Transmission Service Provider (TSP). The duties of the TSP, according to the Functional Model, do not include the determination of a method of calculating the ATC. The three methods suggested in MOD-028 through 030 will be determined as detailed in the Functional Model by the reliability Functions; Planning Authority, Transmission Operator, or Reliability Coordinator; depending on the time horizon of the Studies.

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☐ Yes

   ☒ No

   Comments: The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings.
   FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC.

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: MOD-001 if written correctly will detail has the Transmission Service Provider will: 1) acquire the necessary data to calculculate the ATC; 2) the frequency of calculation; 3) the posting of values of the ATC, ATC formula components, and the assumptions use to obtain the values of the the ATC formula components. ---- The other Applicable Functions will be in supporting Standards for TTC/TFC, CBM, TRM, and ETC.

**4.** Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

☐ Yes

☒ No

Comments: The Requirement 5 should set the Maximum amount of time between calculations. The way it is written is that the Requirement sets a Minimum amount of time between calculations. What if an entity updated the Daily before the 24 hours was up; they would be non-compliant. In addition, since hourly covers the next 168 hours, Daily or Weekly calculations will be overlaping each other, one should be omitted. Note TVA's posted method, while they mention Daily and Weekly, they only post Daily for 30 days.

**5.** Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: Available Transfer Capability Implementation Document (ATCID) is redundant should not be made a requirement of the TSP. The ATC is just the algebraic sum of the four components; TTC, ETC, CBM, and TRM. What ever method is used to calculate the TTC, i.e. Flow Gate, Rated System Path, or Network is determined by the planners; RC or TOP and the assumptions will accompany the TTC/TFC values and be posted. The complete description of the ATC calculation is contained in the assumptions of the other components, CBM, TRM, and ETC, which will be posted on the OASIS or other electronic means.

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments: The posting that are listed are for TTC, the SDT needs to address the assumptions for the other components.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: What is meant by "evaluation of the transmission service request?" If "evaluation of the transmission service request" is prioritizing the transmission service requests base on a predetermined set of rules, the answer is no. Rules to prioritize transmission service requests are based upon negotiated or regulated terms that are a business decision, not reliability.mean by the evaluation of transmission requests? Evaluation of the transmission service request for reliability issues will be made by TOPs or BAs.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: Requirements within this proposed standard deal with the assumptions that will be required by those functions that determine TTC.

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: The Standard is written much like a Policy and it cannot be determined who is responsible for the different calculations of the components of the ATC. The Standard does not provide the Compliance Monitor or the TSP who calculates the Hourly. Daily, and Monthly ATCs with the necessary requirements to know what is necessary to be compliant. A copy of a Draft MOD-001 that has been written in a Standard Format that will permit the Compliance Monitor and the Applicable Functions to respond to measureable requirements is attached for the SDT review and comments.

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| **Individual Commenter Information** | | |
|---|---|---|
| **(Complete this page for comments from one organization or individual.)** | | |
| Name: | Stephen Tran | |
| Organization: | BC Transmission Corportation | |
| Telephone: | (604) 699-7363 | |
| E-mail: | stephen.tran@bctc.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

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   ☐ Yes

   ☐ No

   Comments:

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: ATC related standards should be applicable only to entities who have the obligation to provide non-discrimintory transmission service, that is the Transmission Service Providers.

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☒ No

   Comments: The calculation frequency is a business practice and should not be part of NERC standards.

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments:

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: Evaluation of Transmission Service Requests is a tariff and business issue not a reliability issue.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments:

A.

The horizons described in R2 are not consistent with FAC-010 and FAC-011, which describe the operating horizon and up to one year. These terms are not capitalized and defined anywhere, so I am not going to say that MOD is incorrect. there is a potential for confusion and iscommunications between the planners and the Transmission Service Providers.

B

The requirement "subject to security and confidentiality requirements" in R6 is in conflict with FERC's Standards of Conduct. The TSPs may not provide transmission information discriminatorily.

C

R6.9 is unclear.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
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**Contact Segment:**

**Contact Telephone:**

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/TFC and ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/TFC and ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability. The proposed version of MOD-001 is an “umbrella” standard and it contains the general requirements applicable to ATC without regards to any particular methodology.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-001-1 ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the ‘White Paper’ and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with “ATC Standard” in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: However, please clarify that "one standard" is MOD-001.

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority.

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☒ No

   Comments: The minimum calculation requirements should mandate recalculation during regular business hours, as opposed to every day at midnight. We suggest leaving the final determination of the proper time for ATC/AFC calculation updates to NAESB, as this is a business practice issue.
   Additionally, R5.5. should be added to address the calculation frequency for annual ATC/AFC values.

**5.** Do you agree the information to be included in the “Available Transfer Capability Implementation Document” that will be made publicly available (as required in R3) is appropriate and sufficient? If “No,” please explain why in the comments area.

☐ Yes

☒ No

Comments: R3.1. should read "… the results of the ATC/AFC calculations may be validated." R3.6. should be added to clarify that the ATCID must only include information pertaining to Posted Paths or Flowgates, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If “No,” please explain why in the comment area.

☒ Yes

☐ No

Comments: Except that R6.8. should read "ATC/AFC recalculation frequency and times."

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: The evaluation of Transmission Service Requests (TSRs) is outside the scope of FERC's Order 890 directives and there is insufficient time left, prior to the scheduled September 18th posting of these standards for balloting, to draft adequate TSR evaluation standards and provide sufficient industry comment periods.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: The ATC MODs (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide narrative descriptions of these methodologies.

The horizons defined in R2.2. and R2.3. need to be reconciled with the Planning and Operating horizons previously defined by NERC.

R5. should be modified to the following:

"R5. Each Transmission Service Provider that calculates ATC for Posted Paths or AFC for Flowgates shall, at a minimum, recalculate those ATC/AFCs at the following frequency:

- R5.1. For hourly ATC/AFC…
- R5.2. For daily ATC/AFC…
- R5.3. For weekly ATC/AFC…
- R5.4. For monthly ATC/AFC…
- R5.5. For yearly ATC/AFC…"

Definitions of the terms "Counter flow" and "Loop flow" are needed, to understand the distinction between the two.

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<table>
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<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☒ ERCOT<br>☒ FRCC<br>☒ MRO<br>☒ NPCC<br>☒ RFC<br>☒ SERC<br>☒ SPP<br>☒ WECC<br>☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
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   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: Neither the standard nor the whitepaper provide enough background information to explain why the structure is necessary. Without the background information it is difficult to determine why this proposed structure is optimal.

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☒ No

   Comments: Specifically, R5.4: a minimum of "once a month" is not enough to facilitate commercial activities. Frequency should be "once a day" with a waiver if the inputs to the model have not changed "significantly" from the previous day. Also, what is the minimum frequency for yearly service?

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

   ☐ Yes

☒ No

Comments: Need to include more details as to how transmission service request are modeled.

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☐ Yes

☒ No

Comments: Need to include Transmission Customers as an entity.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments:

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: What determines which ATC calculation method a transmission service provider adapts or the frequency they can change?

In R4 please add Transmission Customers to the notification list.

In R6 please add Transmission Customers to the list that the transmission service provider will make the information available.

Also, please better define "subject to security and confidentiality requirements."

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| Individual Commenter Information (Complete this page for comments from one organization or individual.) | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
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   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☐ Yes

   ☒ No

   Comments: FAC-012 should be modified to clearly state that the purpose is to provide instructions for calculating transfer capabilities used in regional reliability assessments. The methodologies used for calculating TTC and these transfer capabilities should be similar, but the assumptions will vary due to the different purposes of the calculations. The major difference is that transfer capabilities for use in reliability assessments are generally only calculated once or twice a year for peak season conditions and TTCs are generally calculated more frequently. Additionally, the transfer capabilities used in reliability assessments should use assumptions reflecting a "worst case" scenario, whereas the assumptions used for calculating TTC should reflect the best forecast of conditions for the particular time period the TTC is being calculated for.

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☒ No

   Comments: R5 should be modified to include yearly ATC.

**5.** Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: Need to add another requirement that describes the manner in which the Transmission Service Provider will account for allocation of firm transmission capacity (i.e. reciprocal flowgate allocation).

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☐ Yes

☒ No

Comments: Should specify that the information to be made available is information used in calculation of ATC. Also, need to include flowgate allocation data, identifying any portion of flowgate(s) that have been allocated for firm transmission.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: NAESB should be responsible for business practice standards for evaluation of Transmission Service Requests. The only impact the evaluation of TSRs have on ATC calculations is addressed in MOD-028-1, MOD-029-1 and MOD-030-1.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

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| **Individual Commenter Information** | | |
|---|---|---|
| **(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| George Baretlett | Entergy Services Inc. | **SERC** | Transmission Owner |
| Jim Case | Entergy Services Inc. | **SERC** | Transmission Owner |
| Ed Davis | Entergy Services Inc. | **SERC** | Transmission Ownere |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/TFC and ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/TFC and ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability. The proposed version of MOD-001 is an “umbrella” standard and it contains the general requirements applicable to ATC without regards to any particular methodology.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-001-1 ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the ‘White Paper’ and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with “ATC Standard” in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: Entergy supports this approach.

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☒ Yes

   ☐ No

   Comments: Yes, FAC-012 and FAC-013 can be retired after requirements for TTC/TFC methodologies are included in these standards.

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☒ No

   Comments: Calculation frequency should be linked with the change in elements of ATC that impact ATC. For example Monthly ATC should not be only calculated once a month, rather it should be recalculated when any reservation impacting the Monthly ATC is confirmed, this could be a Daily or Weekly reservation. If a reservation that impacts the Monthly reservation is confirmed on second day of the month, and Monthly ATCs are not recalculated till first day of the next month, the Monthly ATC values for the impacted period will remain inaccurate for the remaining entire month. Recalculation frequency should be included in NAESB business Practice Standard rather than in reliability standard.

**5.** Do you agree the information to be included in the “Available Transfer Capability Implementation Document” that will be made publicly available (as required in R3) is appropriate and sufficient? If “No,” please explain why in the comments area.

☐ Yes

☒ No

Comments: R 3.5 requires to identify only TSPs from which data is received. In practice, TSP may receive data from entities other than TSP's such as PSEs, Generator Operators etc. for calculating transfer capability. Entergy suggests that TSP should identify all suppliers of data in ATCID for calculation of ATCs and not only other TSPs..

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If “No,” please explain why in the comment area.

☐ Yes

☒ No

Comments: It is not clear how other parties can demonstrate reliability need. In addition, in R6.9, it is not clear what is expected under Transmission Reservation impact modeling identification. If response factors are expected, it should be stated as such, or the term impact modeling identification be defined.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: Requirements of evaluation of Transmission Service Requests is not a reliability issue and it does not have to be included in NERC Realiability Standards. Once Transmission Service Request is confirmed, regardless of which evaluation process is used, it should be included in ETC as appropriate. If needed, Transmission Service Request evalulation process should be addressed by NAESB Business Practice Standards.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: Notification as required in R4 is not necessary if the ATCID is to be posted on a public site.

Please use this form to submit comments on the 2nd draft of standard MOD-001-1, Available Transfer Capability. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Steve Myers | | |
| Organization: ERCOT | | |
| Telephone: 512-248-3077 | | |
| E-mail: smyers@ercot.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☒ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☒ | 2 — RTOs and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/TFC and ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/TFC and ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability. The proposed version of MOD-001 is an "umbrella" standard and it contains the general requirements applicable to ATC without regards to any particular methodology.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-001-1 ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "ATC Standard" in the subject line.

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   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: See IRC comments.

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☒ Yes

   ☒ No

   Comments: ERCOT does not perform these calculations since these concepts are not used within ERCOT. See IRC comments submitted by Charles Yeung.

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: See IRC comments submitted by Charles Yeung.

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: See IRC comments submitted by Charles Yeung.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT region. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area Interconnection and there has been no reservation of transmission capacity in ERCOT.

Available Transfer Capability is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. The ERCOT Interconnection has already moved "beyond" ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therfore both ERCOT and SPP are notified when the DC Tie capability is reduced.

Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.

In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.

In the current and future ERCOT market design the method of calculating ATC, TTC and the use of CBM and TRM are not applicable to the ERCOT Region. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the Interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance.

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: See IRC comments submitted by Charles Yeung.

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Dave Folk | | |
| Organization: FirstEnergy Corp. | | |
| Telephone: 330-384-4668 | | |
| E-mail: folkd@firstenergycorp.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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**Group Name:**

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**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Richard Kovacs | FirstEnergy Corp. EDPP | | |
| Phil Bowers | FirstEnergy Corp. EDPP | | |
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   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once and eliminate duplication.

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☒ Yes

   ☐ No

   Comments: FAC-012 and 013 are similar in scope to MOD-001 and should be retired once MOD-001 is revised.

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☒ Yes

   ☐ No

   Comments: R5 should require recalculation of ATC as interchange schedules or transmission reservations change.

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

Comments: R3 gives the TSP a lot of leeway in how it implements the calculations that it performs under this standard. R3.1 is not specific enough to meet the intent of 693-1057, additional detail on required elements is needed to insure that adequate data is exchanged to enable the duplication and verification of the calculations for validation..

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments: Overall R6 addresses data sharing beter than it does the uniformity of the data. R6 should specify the time periods and method (electronic?) for sharing the specified data. In addition, it should specify the time period of the data to be shared - future data, past data, or both. As written, R6 leaves too much leeway to meets the stated purpose of promoting the consistent and uniform application and documentation of ATC calculations. Lastly, R6 requires the sharing of data with other parties with a demonstrated reliability need, methods are needed for determining that a reliability need has been demonstrated, who will make this determination, and for resolving conflicts.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: MOD-001 should include the Transmission Service Request evaluation rules necessary to maintain the relaibility of the Bulk Electric System.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: R1 requires agreement on methodology among TSP, PCs and RCs and should include a method for handling disagreements.

R2 implies need for incorporating schedules but does not imply or explicitly state the incorporation of transmission reservations.

R4.8 should require a written request as a means of formally documenting the request was made, received, and acknowledged.

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Roger Champagne | | |
| Organization: Hydro-Québec TransÉnergie | | |
| Telephone: 514 289-2211, X 2766 | | |
| E-mail: champagne.roger.2@hydro.qc.ca | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Danielle Beaulieu | Hydro-Québec TransÉnergie | **NPCC** | 1 |
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Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer/Flowgate Capability (TTC)/(TFC) and Available Transfer/Flowgate Capability (ATC)/(AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/TFC and ATC/AFC calculations and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/TFC and ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/TFC and ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/TFC and ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability. The proposed version of MOD-001 is an “umbrella” standard and it contains the general requirements applicable to ATC without regards to any particular methodology.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-001-1 ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the ‘White Paper’ and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with “ATC Standard” in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☒ Yes

   ☒ No

   Comments: Are FAC-012 and FAC-013 intended to be for only interfaces where transmission service is sold? If not, and these standards are intended to cover the establishment of intra-area interfaces, then the retirement of these standards would be leaving a gap that is not covered by other standards.

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☒ No

   Comments: (1) Language needs to be clear that TSPs only have to calculate ATC for durations of service that they offer.
   (2) Regarding the frequency of the updates; it should be clear that if no inputs have changed that no recalculations are required. For example, for those entities that update ATC automatically based on receipt of service requests or a change in TTC, it would be burdensome to 'recalculate' on this stated frequency with no added value.
   (3) Regarding the timing of the updates; Suggest replace 'at' with 'no later than' so that the auditing aspect of this requirement is reasonable. Entities would be allowed to have calculated that data at any time prior to this required time point. Required timing of updates to be 'at' a

specific time creates an auditing trap. For example, how long does it take to perform a set of ATC calculations? Is this requiring that calculations be started at this time or completed by this time? Knowing when the calculations are completed will also provide a known time point for the posting requirements to be developed by NAESB.

**5.** Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments:

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: The evaluation of Transmission Service Requests is a Business Practice and should continue to be addressed under NAESB

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: The current wording of Requirement 5 contains language that dictates precisely when ATC calculations must occur. There are areas with existing market rules and corresponding tariffs that dictate when publications of data occur (for example - after the clearing of a Day Ahead Market). NERC standards do not have the authority to require wholesale changes to existing market structures. Therefore, the wording of the timing of the required ATC calculations must be more general.

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: For those entities that do not provide physical transmission service, some of the requirements in these stanards do not apply. With the current arrangement of these proposed standards, the ATCID for these entities would clearly document what requirements of the standards are or are not applicable.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| Name: Ron Falsetti | | |
| Organization: IESO | | |
| Telephone: 905-855-6187 | | |
| E-mail: ron.falsetti@ieso.ac | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: We do not have a strong view one way or the other on splitting the former MOD-001 into various standards with some of them each addressing an ATC calculation methodology. However, we have some fundamental disagreements with some of the standards as drafted. Unfortunately, the SAR that proposed the split has not provided the scope and description of what went into the draft standards such as MOD-001, MOD-028, MOD-029 and MOD-030, which in our view should have been posted for review and comments before this and the other MOD standards are drafted.

   Specific to this draft standard, we have a number of concerns and comments which we will list below.

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☐ Yes

   ☒ No

   Comments: Owing to the various concerns we have over MOD-001, MOD-028 to MOD-030, we are unable to determine at this time whether or not FAC-012 and FAC-013 can or cannot be retired until we see the more refined versions of the MOD standards.

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: The RC and PC do not have a role in MOD-001 as they are neither responsible for calculating ATC, nor are they responsible for implementing or agreeing to a method for use in calculating ATC.

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

☒ Yes

☐ No

Comments: We generally agree.

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: We do not know what this Available Transfer Capability Implementation Document (ATCID) is intended to provide and serve. Is this a document that resembles or replaces the existing Regional ATC Methodology document? If so, there is much more information to be provided. For example, coordination with neighboring TSPs on ATC calculation, interface definitions, path names, etc.

Notwithstanding the above concerns, we do not understand why the RC and the PC need to be identified in R3.3 but not the TOP.

6. Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☒ No

Comments: Though it is not stated in the requirement, we assume these data are related to ATC calculation. Some of the data do not support reliability need (e.g. time and frequency of ATC calculation), while there may be some that do but not listed. There are also some data that are proprietray information for which consent of the information owner must be sought before they can be disseminated. But until we see a more refined set of standards that better align roles and responsibilities, we are unable to provide any specific inputs to the completeness and appropriateness of the list.

In R6.5 – By Transmission Reservations, does the requirement mean both "firm" and "non-firm" reservations?

In R6.6 – The requirement should state both power flow models and the underlying modeling assumptions including the modeling of generators in the first-tier control areas.

The list of single and multiple element contingencies included in the ATC calculation should also be provided.

7. Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: It'd be best to keep this standard to calculating ATC only. Evaluation of transmission service request belongs to another standard, or even a NAESB businesss practice.

8. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments: Not aware of any conflicts but it should be pointed out that some entities do not provide physical transmission services. Hence, these standards or some of the requirements in these standards may not apply.

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: Please see our high level comments to the SAR which we feel need to be addressed first before providing any comments specific to this standard.

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Group Comments (Complete this page if comments are from a group.)

**Group Name:** IRC Standards Review Committee

**Lead Contact:** **Charles Yeung**

**Contact Organization:** **SPP**

**Contact Segment:** **2**

**Contact Telephone:** **832-724-6142**

**Contact E-mail:** **cyeung@spp.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Jim Castle | NYISO | **NPCC** | 2 |
| Alicia Daugherty | PJM | **RFC** | 2 |
| Ron Falsetti | IESO | **NPCC** | 2 |
| Matt Goldberg | ISO-NE | **NPCC** | 2 |
| Brent Kingsford | CAISO | **WECC** | 2 |
| Steve Myers | ERCOT | **ERCOT** | 2 |
| Anita Lee | AESO | **WECC** | 2 |
| Bill Phillips | MISO | **RFC+** | 2 |
| | | **MRO+** | |
| | | **SERC+** | |
| | | **SPP** | |
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   ☐ Yes

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4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

☐ Yes

☒ No

Comments: The calculation frequency is not consistent across all methodologies. The frequency should allow for time to validate the values calculated. It may not be consistent with currently filed FERC Operating Agreements, which is not a minimum requirement for the whole industry.

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☐ Yes

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Matthew F. Goldberg | | |
| Organization: ISO New England | | |
| Telephone: 413 535 4029 | | |
| E-mail: mgoldberg@iso-ne.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

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1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments: While the RC and the PC do not calculate ATC, they are responsible for calculating TTC which is a direct input to the ATC calculation. Since the selection of the TTC methodology will determine which ATC standard is utilized by the TSP, it is appropriate for the RC and the PC to be applicable entities in this standard. While it is not specifically stated in R1 and R2 that the RC and PC are involved solely because of their involvement in TTC, the MOD-028, MOD-029 and MOD-030 clearly deliniate the responsibility for those entities.

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☒ No

   Comments: (1) Language needs to be clear that TSPs only have to calculate ATC for durations of service that they offer.
   (2) Regarding the frequency of the updates; it should be clear that if no inputs have changed that no recalculations are required. For example, for those entities that update ATC automatically based on receipt of service requests or a change in TTC, it would be burdensome to 'recalculate' on this stated frequency with no added value.

(3) Regarding the timing of the updates; Suggest replace 'at' with 'no later than' so that the auditing aspect of this requirement is reasonable. Entities would be allowed to have calculated that data at any time prior to this required time point. Required timing of updates to be 'at' a specific time creates an auditing trap. For example, how long does it take to perform a set of ATC calculations? Is this requiring that calculations be started at this time or completed by this time? Knowing when the calculations are completed will also provide a known time point for the posting requirements to be developed by NAESB.

**5.** Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments:

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: The evaluation of Transmission Service Requests is a Business Practice and should continue to be addressed under NAESB

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: The current wording of Requirement 5 contains language that dictates precisely when ATC calculations must occur. There are areas with existing market rules and corresponding tariffs that dictate when publications of data occur (for example - after the clearing of a Day Ahead Market). NERC standards do not have the authority to require wholesale changes to existing market structures. Therefore, the wording of the timing of the required ATC calculations must be more general.

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments:

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<table>
<tr><th colspan="3">Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name: Brian Thumm</td></tr>
<tr><td colspan="3">Organization: ITC</td></tr>
<tr><td colspan="3">Telephone: 248-374-7846</td></tr>
<tr><td colspan="3">E-mail: bthumm@itctransco.com</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☐ NPCC<br>☒ RFC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
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**Lead Contact:**

**Contact Organization:**

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**Contact Telephone:**

**Contact E-mail:**

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   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☒ No

   Comments: This is a qualified yes. The three methodsologies will make it easier for the various regions in the country to comply with the standards. A single standard would be best, but it would come at a cost for entities to adapt to the single methodology if they are in an area that would have to implement changes to comply with the chosen methodology. The costs would likely not be prohibitive, however, and FERC could mandate a single methodology if they so chose to. We would prefer MOD-030 as a single standard. As the three methodologies now exist, MOD-030 appears to provide the greatest flexibility and accuracy.

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☒ Yes

   ☒ No

   Comments: We never thought FAC-012 or -013 should apply to ATC calculations. They are a system "test" and not a rigorous calculation of TTC for sale of transmission service.

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: We understand that certain areas of the country may want Reliability Coordinators to be responsible entities, perhaps because they wear both the RC and TSP hat, but this is not a reason to include them. In the MISO footprint, it makes no sense to include the RC. However, we do think that a list of applicable entities should include the "Transmission Planner," as has been indicated in MOD-004 and MOD-008. This is more appropriate than the RC. As written, several entities are excluded from the applicability statement.

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☒ Yes

   ☐ No

Comments:

**5.** Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☒ Yes

☒ No

Comments: The more transparency there is in the process (except for commercially sensitive data), the better the process will be.

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☐ Yes

☒ No

Comments: We agree that what is asked for is appropriate, but it may not be sufficient. For example, the ratings provided should include "any value used to limit AFC/ATC." Ratings can have time, temperature, and seasonal adjustments. As written, compliance might mean just a single ratings set. This could be handled in the compliance and measures section but additional thought should be given to this section.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: This could be in measures and compliance and not necessarily in the requirements.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: Certain areas of the country have tariffs (such as New England) that were approved by FERC and do not require the sale of transmission service. These areas could be saved a lot of grief by excluding them from these standards. However, they should be required to provide any data to their neighbors (such as their impacts on neighbor system flows) that might impact ATC calculations.

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: Given that three methods are acceptable for calculating AFC/ATC, MOD-001 is a necessary prelude to any methodology chosen.

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|---|---|---|
| Name: Michelle Rheault | | |
| Organization: Manitoba Hydro | | |
| Telephone: 204-487-5445 | | |
| E-mail: mdrheault@hydro.mb.ca | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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   ☒ Yes

   ☐ No

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   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☒ No

   Comments: No direct instruction for informing public of ongoing ATC values is provided, although this process is an implied result of adhering to R3.1 and R5.

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments:

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☐ Yes

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Tom Mielnik | | |
| Organization: MidAmerican Energy Company | | |
| Telephone: 563-333-8129 | | |
| E-mail: tcmielnik@midamerican.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: I agree with team's decision to structure the standards in this manner but I have some comments about it. I believe the Standards Drafting Team should make it clearer in the MOD-001-1 that while one or more of the methods provided in MOD-028 through MOD-030 may be used by one party across a system, only one of these methods is to be used for a particular flowgate or for a particular path.

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☐ Yes

☒ No

Comments: FAC-012 and FAC-013 need to be revised as necessary to cover other reliability needs for Transfer Capability measurements such as for unusual operating conditions that do not need to be the basis for commercial offerings.

**3.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**4.** Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

☐ Yes

☒ No

Comments: In practice in the industry, the calculation frequency is not consistent across all methodologies. In some cases the times for posting and the frequency of recalculations are slower to allow for time to validate the values calculated. I believe that reliability will suffer if validation is eliminated so as to meet a target that is set by the Standard.

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**5.** Do you agree the information to be included in the “Available Transfer Capability Implementation Document” that will be made publicly available (as required in R3) is appropriate and sufficient? If “No,” please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If “No,” please explain why in the comment area.

☒ Yes

☐ No

Comments:

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: Transmission request evaluation is not the subject of this standard. If there are reliability reasons that require a standard that should be the subject of a new SAR and a new Standards Drafting Team.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

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Please use this form to submit comments on the 2nd draft of standard MOD-001-1, Available Transfer Capability. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Dennis Kimm | |
| Organization: | MidAmerican Energy - Generation/Trading | |
| Telephone: | 515 252 6737 | |
| E-mail: | ddkimm@midamerican.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☒ **MRO** | ☐ | 3 — Load-serving Entities |
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| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/TFC and ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/TFC and ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability. The proposed version of MOD-001 is an “umbrella” standard and it contains the general requirements applicable to ATC without regards to any particular methodology.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-001-1 ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the ‘White Paper’ and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with “ATC Standard” in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☐ Yes

   ☒ No

   Comments: MidAmerican Trading believes that only two methodologies really exist and those are a Rated System Path and the Network Response Methodology. Those that do network response are just monitoring a different set of facilities, studying a different set of contingencies and recalculating using the laws of physics with a different frequency. MidAmerican Trading is also concerned that the standard drafting team is still making most of the requirements fill-in-the-blank requirements and more the the requirements should be in MOD-001 and standarized for all methodologies.

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☐ Yes

   ☒ No

   Comments: FAC-012 and FAC-013 should be revised as necessary to clearly state that they are for covering the reliability needs for Transfer Capability measurements such as for unusual operating conditions to help establish operating guides or provide guidance to the operators and that are not the basis for commercial offerings or the for the decisions to accept or deny transmission service requests.

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☒ Yes

   ☐ No

   Comments:

**5.** Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments: The document should also include a technical explanation of how transmission service requests are being evaluated.

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments:

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: ATC values are calculated for the evaluation of Transmission Service. If these processes aren't for the evaluation of TSRs, what are they for?

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: This standard in conjuction with the other MODS (28/29/30) are in direct conflict with FERC order 890 requiring consistency.

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments:

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** Midwest Reliability Organization (MRO)

**Lead Contact:** **Tom Mielnik**

**Contact Organization:** **MRO for Group (GRE - for lead contact)**

**Contact Segment:** **10**

**Contact Telephone:** **563-333-8129**

**Contact E-mail:** **tcmielnik@midamerican.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Neal Balu | WPS | **MRO** | 10 |
| Terry Bilke | MIS0 | **MRO** | 10 |
| Robert Coish, Chair | MHEB | **MRO** | 10 |
| Carol Gerou | MP | **MRO** | 10 |
| Ken Goldsmith | ALT | **MRO** | 10 |
| Todd Gosnell | OPPD | **MRO** | 10 |
| Jim Haigh | WAPA | **MRO** | 10 |
| Joe Knight | GRE | **MRO** | 10 |
| Pam Oreschnick | XEL | **MRO** | 10 |
| Dave Rudolph | BEPC | **MRO** | 10 |
| Eric Ruskamp | LES | **MRO** | 10 |
| Mike Brytowski, Secretary | MRO | **MRO** | 10 |
| 28 Additional MRO Members | Not named above | **MRO** | 10 |
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| Individual Commenter Information<br>(Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☒ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** NPCC CP9 Reliability Standards Working Group

**Lead Contact:** **Guy V. Zito**

**Contact Organization:** **Northeast Power Coordinating Council**

**Contact Segment:** **10**

**Contact Telephone:** **212-840-1070**

**Contact E-mail:** **gzito@npcc.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Kathleen Goodman | ISO-New England | **NPCC** | 2 |
| Roger Champagne | HydroQuebec TransEnergie | **NPCC** | 1 |
| Ralph Rufrano | New York State Power Authority | **NPCC** | 1 |
| Al Adamson | New York State Reliability Council | **NPCC** | 10 |
| Greg Campoli | New York ISO | **NPCC** | 2 |
| Guy V> Zito | NPCC | **NPCC** | 10 |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☒ Yes

   ☒ No

   Comments: Are FAC-012 and FAC-013 intended to be for only interfaces where transmission service is sold? If not, and these standards are intended to cover the establishment of intra-area interfaces, then the retirement of these standards would be leaving a gap that is not covered by other standards.

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☒ No

   Comments: (1) Language needs to be clear that TSPs only have to calculate ATC for durations of service that they offer.
   (2) Regarding the frequency of the updates; it should be clear that if no inputs have changed that no recalculations are required. For example, for those entities that update ATC automatically based on receipt of service requests or a change in TTC, it would be burdensome to 'recalculate' on this stated frequency with no added value.
   (3) Regarding the timing of the updates; Suggest replace 'at' with 'no later than' so that the auditing aspect of this requirement is reasonable. Entities would be allowed to have calculated that data at any time prior to this required time point. Required timing of updates to be 'at' a

specific time creates an auditing trap. For example, how long does it take to perform a set of ATC calculations? Is this requiring that calculations be started at this time or completed by this time? Knowing when the calculations are completed will also provide a known time point for the posting requirements to be developed by NAESB.

**5.** Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments:

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: The evaluation of Transmission Service Requests is a Business Practice and should continue to be addressed under NAESB

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☒ Yes

☐ No

Comments: The current wording of Requirement 5 contains language that dictates precisely when ATC calculations must occur. There are areas with existing market rules and corresponding tariffs that dictate when publications of data occur (for example - after the clearing of a Day Ahead Market). NERC standards do not have the authority to require wholesale changes to existing market structures. Therefore, the wording of the timing of the required ATC calculations must be more general.

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: For those entities that do not provide physical transmission service, some of the requirements in these stanards do not apply. With the current arrangement of these proposed standards, the ATCID for these entities would clearly document what requirements of the standards are or are not applicable.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Harvie Beavers | |
| Organization: | Piney Creek LP | |
| Telephone: | 814-226-8001 | |
| E-mail: | harvie-pclp@csonline.net | |

| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☒ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
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| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**2.** This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

☒ Yes

☐ No

Comments:

**3.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments: You may desire to 'reference' the generator rating standards (FAC-005-0/FAC-009-1) that requires submission of facility ratings where needed.

**4.** Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

☒ Yes

☐ No

Comments:

**5.** Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments:

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: This may be desirable if/when TSR's are unable to be fulfilled

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments:

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Bill Lohrma | | |
| Organization: Prague Power, LLC | | |
| Telephone: 908-630-0289 | | |
| E-mail: wwlohrman@praguepower.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☒ Yes

   ☐ No

   Comments:

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☐ Yes

☒ No

Comments: The entities calculating ATC should also be required in Requirement R6to include and honor third party flowgate/path limitations in their ATC calculations if that data is provided by affected third parties.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☒ Yes

☐ No

Comments: a procedure should be established to reconcile differences across seams

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments: n/a

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| Organization: | | |
| Telephone: | | |
| E-mail: | | |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** Public Service Commission of South Carolina

**Lead Contact:** **Phil Riley**

**Contact Organization:** **Public Service Commission of South Carolina**

**Contact Segment:** **9**

**Contact Telephone:** **803-896-5154**

**Contact E-mail:** **philip.riley@psc.sc.gov**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mignon L. Clyburn | Public Service Commission of SC | **SERC** | 9 |
| G. O'Neal Hamilton | Public Service Commission of SC | **SERC** | 9 |
| John E. "Butch" Howard | Public Service Commission of SC | **SERC** | 9 |
| Randy Mitchell | Public Service Commission of SC | **SERC** | 9 |
| C. Robert "Bob" Moseley | Public Service Commission of SC | **SERC** | 9 |
| David A. Wright | Public Service Commission of SC | **SERC** | 9 |
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   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

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   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☒ Yes

   ☐ No

   Comments:

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments:

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☐ Yes

☒ No

Comments:

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

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| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

| | |
|---|---|
| Group Comments (Complete this page if comments are from a group.) | |
| **Group Name:** | Southern Company |
| **Lead Contact:** | **DuShaune Carter** |
| **Contact Organization:** | **Southern Company Services** |
| **Contact Segment:** | |
| **Contact Telephone:** | **205-257-5775** |
| **Contact E-mail:** | **ddcarter@southernco.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| JT Wood | Southern Company Services | **SERC** | 1 |
| Roman Carter | Southern Company Services | **SERC** | 1 |
| Gary Gorham | Southern Company Services | **SERC** | 1 |
| Marc Butts | Southern Company Services | **SERC** | 1 |
| Bill Botters | Southern Company Services | **SERC** | 1 |
| Ron Carlsen | Southern Company Services | **SERC** | 1 |
| Jim Howell | Southern Company Services | **SERC** | 1 |
| Jeremy Bennett | Southern Company Services | **SERC** | 1 |
| Jim Viikinsalo | Southern Company Services | **SERC** | 1 |
| Reed Edwards | Southern Company Services | **SERC** | 5 |
| Dean Ulch | Southern Company Services | **SERC** | 1 |
| Garey Rozier | Southern Company Services | **SERC** | 5 |
| Karl Moor | Southern Company Services | **SERC** | 1 |
| Chuck Chakravarthi | Southern Company Services | **SERC** | 1 |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/TFC and ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/TFC and ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability. The proposed version of MOD-001 is an “umbrella” standard and it contains the general requirements applicable to ATC without regards to any particular methodology.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-001-1 ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the ‘White Paper’ and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with “ATC Standard” in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☒ No

   Comments: The requirement is too prescriptive with respect to the times that the calculations need to be performed. Other processes (e.g., ramps, schedule updates, etc) are also being performed across the top of the hour. Each TSP should be allowed the flexibility to set a more appropriate time for recalculations.

   This requirement should also not require a recalculation of ATC unless the one of the components of the ATC equation changes.

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☐ Yes

☒ No

Comments: It is unclear why the TSP should exchange ATC recalculation frequency and times in R6.8 when they are prescribed in R5.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: The evaluation of Transmission Service Request are governed by the tariff and should remain so.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments:

1. As drafted, it is not completely clear as to which of the requirements would apply to long-term planning and which requirements would not apply. For example, R5 clearly limits the timeframe of the requirement to 13 months. However, R6 has no reference or indication of which timeframes this requirement would be applicable.

2. R6 requires that the data in R6.1 - R6.9 is shared with ". . . or other party with a demonstrated reliability need. . . ." To avoid potential conflicts with this data sharing, the term "reliability need" should be limited to those needs required to maintain reliability of the transmission system.

Please use this form to submit comments on the 2nd draft of standard MOD-001-1, Available Transfer Capability. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
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| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** SERC Available Transfer Capability Working Group (ATCWG)

**Lead Contact:** **John Troha**

**Contact Organization:** **SERC Reliability Corporation**

**Contact Segment:** **10 - RRO**

**Contact Telephone:** **704-948-0761**

**Contact E-mail:** **jtroha@serc1.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Darrell Pace | Alabama Electric Cooperative, Inc | SERC | 10 |
| Helen Stines | Alcoa Power Generating, Inc. | | |
| Eugene Warnecke | Ameren | | |
| Don Reichenbach | Duke | | |
| Joachim Francois | Entergy | | |
| Ross Kovacs | Georgia Transmission Corporation | | |
| Larry Middleton | Midwest ISO | | |
| Jerry Tang | Municipal Electric Authority of Georgia | | |
| John Troha | SERC Reliability Corporation | | |
| Al McMeekin | South Carolina Electric and Gas Company | | |
| Stan Shealy | South Carolina Electrica nd Gas Company | | |
| Carter Edge | SERC Reliability Corporation | | |
| DuShaune Carter | Southern Company Services, Inc. -Trans | | |
| Bryan Hill | Southern Company Services, Inc. -Trans | | |
| Doug Bailey | Tennessee Valley Authority | | |
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The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability. The proposed version of MOD-001 is an "umbrella" standard and it contains the general requirements applicable to ATC without regards to any particular methodology.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-001-1 ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☒ No

   Comments: Calculation frequency should be based on changes in system conditions or granting of additional transmission service. Calculations based on a set frequency would not improve reliability.

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

   ☒ Yes

   ☐ No

   Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☐ Yes

☒ No

Comments: R6.9 needs clarification.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: The MOD standards define the bounds for reliably selling transmission service. Tarriff admin and business practices are based on FERC approved tarriffs that operate within these bounds.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments:

Please use this form to submit comments on the 2nd draft of standard MOD-001-1, Available Transfer Capability. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | W. Shannon Black Et Al ; Sacramento Municipal Utility District | |
| Organization: | On Behalf of WECC MIC MIS ATC TF ; Varied Ballot Body Segments | |
| Telephone: | (916) 732-5734 | |
| E-mail: | sblack@smud.org | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** WECC MIC MIS ATC TF

**Lead Contact:** **W. Shannon Black**

**Contact Organization:** **Sacramento Municipal Utility District**

**Contact Segment:** **Various**

**Contact Telephone:** **(916) 732-5734**

**Contact E-mail:** **sblack@smud.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| The 24 individuals listed in this same section for MOD-01 comments, filed jointly with this filing, by the WECC MIC MIS ATC TF Team, have either actively monitored this work product or have actively engaged in drafting the attached comments. That Team list of 24 individuals applies to jointly to MOD-01; MOD-04; MOD-08; MOD-29 and MOD-30. | | | |
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

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Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**2.** This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

☒ Yes

☐ No

Comments:

**3.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

☐ Yes

☒ No

Comments:

First, the "Applicability" section uses the term "Planning Coordinator" which is not a defined term in the NERC Glossary. If the NERC Team intends it use, it should become a defined term.

Second, where the term Planning Coordinator is used, WECC queries whether or not the more accurate entity would be the Transmission Planner.

Third, this Standard should not apply to the Reliability Coordinator. The RC should be removed from R1 and R2. (See comments appended.)

**4.** Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

☐ Yes

☒ No

Comments:

1)

The minimum calculation requirements should require recalculation during regular business hours, as opposed to every day at midnight.

2)
Currently, most of WECC utilizes OATI. If the OATI system is required to recalcuate the entire West at a single moment, that system may not be capable of doing the calcuations. Since OATI currently recalulates continuously as variables change, can the NERC Team draft language to allow for a recalculation or reposting within an hour as opposed to all entities doing so at a specified moment?

3)
The WECC Team in general has the following question of interpretation for the NERC Team. To the extent the WECC Team does not understand "how" tocomply with the requirements, it would seem the requirements are either overly vague or unenforceable as written. Please answer the appended question and rewrite for clarity.

The question revolves around the calculation frequency and required recalculation (forecasts?) of ATC going forward:

A. Does this recalculation requirement in any way mandate that transmission providers should adjust (hourly, daily, etc) ATC in response to network load variations?
Taken as currently written, this standard could be interpreted to require TPs to (1) forecast load variations, by path, by day (or hour), (2) reduce network (and possibly PTP) load reservations, "freeing up" future daily (or hourly if offered) ATC and (3) sell firm capacity going forward in response to a load forecast on a path by path basis. This is not a reasonable expectation for TPs to be 100% accurate in load forecasts, and this standard, if making the requirement outlined in the above interpretation, should be clarified to require TPs to update ATC only in response to future capacity sold, and not be required to reduce network reservations as a response to load forecasts to allow future short term firm sales on a daily (or hourly if offered) basis.

In the interpretation outlined above, if the transmission provider (or LSE) is incorrect in load forecasts, and the TP has sold short term firm in these "freed up" ATC periods, it would restrict network (and PTP) customers from scheduling up to their "before the hour" rights without curtailment.

**5.** Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments: The WECC Team concurs that the stated content of the ATCID is appropriate. However, the term "ATCID" is used as a defined term without a definition. It is also used in multiple other standards. It should either be a defined term in the NERC Glossary or, at minuimum, must be cross referenced from all other standards back to this standard.

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☐ Yes

☒ No

Comments: See 9.D. below.

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: Evaluation of Transmission Service Requests is outside the scope of the Order(s) and more appropriately falls into the purview of NAESB as a Business Practice.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments:

A.

As to the "Horizons" identified in the draft at R2, the WECC MIC MIS ATC TF opines that there is no singular practice across the industry as to "Horizons"; however those provided by FERC do not generally comport with how the industry uses those terms.

The WECC Team suggests that the terms utilized in the draft are at best unclear and at worst not consistent with industry usage. It is suggested these "Horizons" be defined by NAESB as part of the ATC process and that their definitions be established in a manner that best reflects accurate industry usage.

B. R1. requires TSPs, PCs and RC to "agree upon and implement" a methodology. The standard suggests no remedy if the three parties cannot "agree." The Team suggests the TSP should be the sole entity to select the methodology. The TSP should have a condition precedent to consult with the PC and RC before selection and a condition subsequent to inform the PC and RC of the selection, seek counsel from those entities on how the methodology should be implemented and ultimately inform the PC and RC as to how that selected methodology will be implemented.

C. R5. Should read:

"Each Transmission Service Provider that calculates ATC for a Posted Path shall, at minimum…"

This requires the addition of the below FERC approved term as excerpted from 18 CFR 37.6 and as utilitized in NAESB R0-4005 in compliance with Order 889. (References below):

Posted Path

Posted Path means: 1) Any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. See also: 18 CFR 37.6; http://a257.g.akamaitech.net/7/257/2422/12feb20041500/edocket.access.gpo.gov/cfr_2004/aprqtr/pdf/18cfr37.5.pdf

D. R6.

There is a concern that where two entities have not selected the same methodology, and where one requests data from the other, the requesting entity must still provide the requested data even if that data is not utilized in the methodology of the providing entity. In other words, an entity cannot be allowed to refuse data provision simply because that entity doesn't use such data in its selected methodology. The Requirement as drafted does not make this clear.

Please use this form to submit comments on the 2nd draft of standard MOD-001-1, Available Transfer Capability. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with “ATC Standard” in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
|---|---|
| Name: | Chuck Falls |
| Organization: | Salt River Project |
| Telephone: | 602 236-0965 |
| E-mail: | Chuck.Falls@srpnet.com |

| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☒ **WECC**<br>☐ **NA – Not Applicable** | ☒ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs and ISOs |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer/Flowgate Capability (TTC)/(TFC) and Available Transfer/Flowgate Capability (ATC)/(AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/TFC and ATC/AFC calculations and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/TFC and ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/TFC and ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/TFC and ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability. The proposed version of MOD-001 is an "umbrella" standard and it contains the general requirements applicable to ATC without regards to any particular methodology.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-001-1 ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the 'White Paper' and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with "ATC Standard" in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

   Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

   ☐ Yes

   ☐ No

   Comments:

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments: .

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

   ☐ Yes

   ☐ No

   Comments:

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

   ☐ Yes

   ☐ No

   Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If “No,” please explain why in the comment area.

☐ Yes

☐ No

Comments:

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☐ No

Comments:

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If “Yes,” please identify the conflict in the comments area.

☐ Yes

☐ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments:

R2 - More clarification is required regarding exactly what period of time each of the time horizons represent.

Please use this form to submit comments on the 2nd draft of standard MOD-001-1, Available Transfer Capability. Comments must be submitted by **June 24, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with "ATC Standard" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| Individual Commenter Information<br>(Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: Clay Young | | |
| Organization: South Carolina Electric & Gas | | |
| Telephone: 803-217-9129 | | |
| E-mail: cyoung@scana.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☒ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs and ISOs |
| | ☒ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer/Flowgate Capability (TTC)/(TFC) and Available Transfer/Flowgate Capability (ATC)/(AFC). Project 2006-07 requires that specific reliability practices be incorporated into the TTC/TFC and ATC/AFC calculations and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/TFC and ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/TFC and ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/TFC and ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The standard drafting team was charged with revising the set of modeling standards related to ATC to comply with the FERC directives and stakeholder recommendations

The standard drafting team posted Draft 1 of standard MOD-001-1, ATC and AFC Calculation Methodologies, for a 30-day comment period beginning February 15, 2007. As stated in the comment form at that time, MOD-001-1 outlined the requirements for calculation of ATC and AFC, but did not provide requirements for the calculation of TFC or TTC. The drafting team identified two standardized methods of calculating TTC and from those values ATC, and one standardized method of calculating TFC and from that value AFC and a conversion to ATC. These methods are presented in the drafts being posted of three new standards: MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability. The proposed version of MOD-001 is an “umbrella” standard and it contains the general requirements applicable to ATC without regards to any particular methodology.

The standard drafting team would like to receive industry comment on the proposed requirements and structure of MOD-001-1 ATC. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please review the ‘White Paper’ and the revised MOD-001 before answering the questions on the following pages. Comments must be submitted by **June 24, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with “ATC Standard” in the subject line.

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow.

Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**2.** This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

☒ Yes

☐ No

Comments:

**3.** Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

☐ Yes

☐ No

Comments:

**4.** Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

☐ Yes

☒ No

Comments: Recalculation of TTC/TFC should be due to a change in system conditions that warrant a recalculation. Recalculation of ATC/AFC should be due to a change in one or more of the components included in the ATC/AFC calculation formula (including TTC/TFC). No set frequency should be set for these calculations.

**5.** Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

☒ Yes

☐ No

Comments:

**6.** Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

☒ Yes

☐ No

Comments:

**7.** Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

☐ Yes

☒ No

Comments: NAESB Business Practices and OATT requirements should address this.

**8.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

☐ Yes

☒ No

Comments:

**9.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

Comments:

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

**Consideration of Comments on 2nd Draft of Standard MOD-001-1 — Available Transfer Capability (Project 2006-07)**

The ATC Standard Drafting Team requesters thank all commenters who submitted comments on the second draft of standard MOD-001-1, Available Transfer Capability. This standard was posted for a 30-day public comment period from May 25 through June 24, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 26 sets of comments, including comments from 107 different people from more than 60 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received from stakeholders, comments from the cooperative effort with NAESB in developing associated business practices, and comments received from FERC staff, the drafting team has significantly redrafted the standard. The changes have been so extensive that the revised standard bears very little resemblance to the last posted draft. Major changes include:

- Added definitions for Posted Path, Available Transfer Capability Implementation Document (ATCID), Transmission Operator Area, Existing Transmission Commitments (ETC), and Planning Coordinator.
- Modified R1 to change the applicability to the Transmission Operator and to clarify that the selected ATC methodologies are for use in determining transfer capabilities of those facilities for each Posted Path per time period within the Planning coordinator's planning area.
- Modified the purpose to clarify that the intent of the standard is to provide, 'transparent' rather than 'uniform' ATC calculations
- Eliminated the Planning Coordinator and Reliability Coordinator as applicable entities – and added the Transmission Operator.
- Modified the requirement to select the methodology for calculating ATC so this responsibility is assigned to the Transmission Operator rather than the Transmission Planner, Transmission Service Provider and Reliability Coordinator
- Modified the requirement to calculate ATC so this responsibility is assigned to the Transmission Operator and Transmission Service Provider rather than to the Planning Coordinator, Reliability Coordinator and Transmission Service Provider
- Updated the time frames for the Transmission Operator and Transmission Service Provider to calculate ATC and the time frames for the Transmission Service Provider to update ATC
- Modified requirements that mentioned 'make publicly available' to provide a cleaner handoff with NAESB's business practices – the revised standard requires that the information be 'prepared' – and the associated business practice will address the actual posting of the information
- Added a requirement that the Available Transfer Capability Implementation Document address third party allocation methodologies
- Added a requirement on how to account for counterflows in the calculation of ATC or AFC

- Added a requirement that, when calculating ATC, AFC, and TTC, the Transmission Operator and Transmission Service Provider use assumptions consistent with those used in any associated operations studies or planning studies for the time period studied
- Added much more specificity to the list of ATC calculation data and information that must be provided to others
- Added measures and compliance elements

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Jason Murray (G7) | AESO | | ✓ | | | | | | | | |
| 2. | Darrell Pace (G4) | Alabama Electric Coop., Inc. | | | | ✓ | ✓ | ✓ | | | | |
| 3. | Anita Lee (G1) | Alberta Electric System Operator | | ✓ | | | | | | | | |
| 4. | Helen Stines (G4) | Alcoa Power Generating, Inc. | | | | | | ✓ | ✓ | ✓ | ✓ | |
| 5. | Ken Goldsmith (G2) | ALT | ✓ | | | | | | | | | |
| 6. | Eugene Warnecke (G4) | Ameren | ✓ | | ✓ | | | ✓ | | | | |
| 7. | E. Nick Henery | APPA | ✓ | | | | | | | | | |
| 8. | Jerry Smith (G7) | APS-TP | | | | | | | | | | |
| 9. | Stephen Tran | BC Transmission Corp | ✓ | | | | | | | | | |
| 10. | Dave Rudolph (G2) | BEPC | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 11. | Steve Tran (G7) | BP TX | | | | | | | | | | |
| 12. | Abbey Nulph (G7) (I) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 13. | Rebecca Berdahl (G7) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 14. | Steve Knudsen (G7) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 15. | Charles Mee (G7) | CA Dept Water & Power | | | | | | | | | | |
| 16. | Brent Kingsford (G1) | California ISO | | ✓ | | | | | | | | |
| 17. | Greg Ford (G7) | CISO-TP | | ✓ | | | | | | | | |
| 18. | Israel Melendez | Constellation Energy Commodities | | | | | | ✓ | | | | |
| 19. | Greg Rowland | Duke Energy | ✓ | | ✓ | | | | | | | |
| 20. | Don Reichenbach (G4) | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 21. | Narinder K. Saini | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 22. | George Bartlett | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 23. | Jim Case | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 24. | Ed Davis | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 25. | Joachim Francois (G4) | Entergy Services, Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 26. | Steve Myers (I) (G1) | ERCOT | | ✓ | | | | | | | | |
| 27. | Patricia vanMidde (G7) | FERC Case MRG, Sempra | | | | | | | | | | |
| 28. | Dave Folk | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 29. | Richard Kovacs | FirstEnergy Corp. EDPP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 30. | Phil Bowers | FirstEnergy Corp. EDPP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 31. | Ross Kovacs (G4) | Georgia Transmission Corp. | ✓ | | ✓ | | | | | | | |
| 32. | Joe Knight (G2) | Great River Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 33. | Roger Champagne (I) (G3) | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 34. | Ron Falsetti (I) (G1) | Independent Electricity System Operator (IESO) | | ✓ | | | | | | | | |
| 35. | Lou Ann Westerfield (G7) | IPUC-SP | | | | | | | | | | |
| 36. | Kathleen Goodman (G3) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 37. | Matthew F. Goldberg (I) (G1) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 38. | Brian Thumm | ITC Transco | ✓ | | | | | | | | | |
| 39. | Sueyen McMahon (G7) | LADWP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 40. | Eric Ruskamp (G2) | LES | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 41. | Michelle Rheault | Manitoba Hydro EB | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 42. | Robert Coish | Manitoba Hydro EB | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 43. | Jerry Tank (G4) | MEAG | ✓ | | ✓ | | ✓ | | | | | |
| 44. | Dennis Kimm | MidAmerican Energy – Energy/Trading (MEC Trading) | | | | | ✓ | ✓ | | | | |
| 45. | Tom Mielnik (I) (G2) | MidAmerican Energy Co. (MEC) | | | ✓ | | | | | | | |
| 46. | Bill Phillips (G1) | Midwest ISO | | ✓ | | | | | | | | |
| 47. | Larry Middleton (G4) | Midwest ISO | | ✓ | | | | | | | | |
| 48. | Carol Gerou | Minnesota Power | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 49. | Terry Bilke (G2) | MISO | | ✓ | | | | | | | | |
| 50. | Mike Brytowski (G2) | MRO | | | | | | | | | | ✓ |
| 51. | Jim Castle (G1) | New York ISO | | ✓ | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 52. | Greg Campoli (G3) | New York ISO | | ✓ | | | | | | | | |
| 53. | Ralph Rufrano (G3) | New York State Power Authority | ✓ | | ✓ | | | | | | | |
| 54. | Al Adamson (G3) | New York State Reliability Council | | | | | | | | | | ✓ |
| 55. | Guy V. Zito (G3) | NPCC | | | | | | | | | | ✓ |
| 56. | Todd Gosnell (G2) | OPPD | ✓ | | ✓ | | | ✓ | | | | |
| 57. | Brian Weber (G7) | Pacificorp | ✓ | | | | ✓ | | | | | |
| 58. | Harvie Beavers | Piney Creek | | | | | ✓ | | | | | |
| 59. | Alicia Daugherty (G1) | PJM | | ✓ | | | | | | | | |
| 60. | Bill Lohrman | Prague Power LLC. | | | | | | | | ✓ | | |
| 61. | Philip Riley (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 62. | Mignon L. Clyburn (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 63. | G. O'Neal Hamilton (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 64. | John E. Howard (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 65. | Randy Mitchell (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 66. | C. Robert Moseley (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 67. | David A. Wright (G6) | PSC of South Carolina | | | | | | | | | ✓ | |
| 68. | Chuck Falls | Salt River Project (SRP) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 69. | Chuck Falls (I) (G7) | Salt River Project (SRP) | ✓ | | | | | | | | | |
| 70. | John Troha (G4) | SERC | | | | | | | | | | ✓ |
| 71. | Carter Edge (G4) | SERC | | | | | | | | | | ✓ |
| 72. | Bob Schwermann (G7) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 73. | Brian Jobson (G7) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 74. | Dick Buckingham (G7) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 75. | Dilip Mahendra (G7) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 76. | W. Shannon Black (G7) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 77. | Phil Odonnell (G7) | SMUD- Ops | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 78. | Al McMeekin (G4) | South Carolina Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |
| 79. | Stan Shealy (G4) | South Carolina Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |
| 80. | JT Wood (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 81. | Roman Carter (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 82. | Gary Gorham (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 83. | Marc Butts (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 84. | Bill Botters (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 85. | Ron Carlsen (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 86. | Jim Howell (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 87. | Jeremy Bennett (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 88. | Jim Viikinsalo (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 89. | Reed Edwards (G5) | Southern Company Services, Inc. | | | | | ✓ | | | | | |
| 90. | Dean Ulch (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 91. | Garey Rozier (G5) | Southern Company Services, Inc. | | | | | ✓ | | | | | |
| 92. | Karl Moor (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 93. | Chuck Chakravarthi (G5) | Southern Company Services, Inc. | ✓ | | | | ✓ | | | | | |
| 94. | DuShaune Carter (G5) | Southern Transmission | ✓ | | | | | | | | | |
| 95. | Bryan Hill | Southern Transmission | ✓ | | | | | | | | ✓ | |
| 96. | Charles Yeung (G1) | Southwest Power Pool | | ✓ | | | | | | | | |
| 97. | Casey Sprouse (G7) | Sr. Term Marketer | | | | | | | | | | |
| 98. | Maria Denton (G7) | SRP | | | | | | | | | | |
| 99. | Terri M. Kuehneman (G7) | SRP System Operation | | | | | | | | | | |
| 100. | Raquel Agular (G7) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 101. | Ron Belval (G7) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 102. | Doug Bailey | TVA | ✓ | | ✓ | | ✓ | | | | | |
| 103. | Jim Haigh (G2) | WAPA | ✓ | | | | | ✓ | | | ✓ | |
| 104. | Raymond Vojdani (G7) | WAPA | | | | | | | | | ✓ | |
| 105. | Mike Wells (G7) | WECC | | | | | | | | | | ✓ |
| 106. | Neal Balu (G2) | WPS | | | ✓ | | ✓ | ✓ | | | | |
| 107. | Pam Oreschnick (G2) | XEL | ✓ | | ✓ | | ✓ | ✓ | | | | |

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – IRC Standards Review Committee (IRC)
G2 – MRO Members (MRO)
G3 – NPCC CP9 Reliability Standards Working Group (NPCC CP9 RSWG)
G4 – SERC Available Transfer Capability Working Group (SERC ATCWG)
G5 – Southern Company Services, Inc. (SOCO)
G6 – Public Service Commission of South Carolina (PSC SC)
G7 - WECC MIC MIS ATC Task Force

## Index to Questions, Comments, and Responses

1. As stated above, the drafting team is posting three standards that specify requirements for three different acceptable methods for calculating TTC, TFC, AFC and ATC (i.e., MOD-028 Network Response Available Transfer Capability, MOD-029 Rated System Path Available Transfer Capability and MOD-030 Flowgate Network Response Available Transfer Capability) and one standard that encompasses the requirements that must be followed for calculating ATC, regardless of which of the other three standards are used, including a requirement to use one or more of the other standards, in an attempt to make the standards easier to follow. Do you agree with the drafting team's decision to structure the standards in this manner? If "No," please explain why in the comments area.

**Summary Consideration:** Most commenters who responded to this question support the restructuring.

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The MOD-001 Standard incorrectly assigns duties to the Transmission Service Provider (TSP). The duties of the TSP, according to the Functional Model, do not include the determination of a method of calculating the ATC. The three methods suggested in MOD-028 through 030 will be determined as detailed in the Functional Model by the reliability Functions; Planning Authority, Transmission Operator, or Reliability Coordinator; depending on the time horizon of the Studies. |
| **Response:** The SDT has modified this Standard to assign determination of the method to the Transmission Operator. | | | |
| MEC | | ☑ | I agree with team's decision to structure the standards in this manner but I have some comments about it. I believe the Standards Drafting Team should make it clearer in the MOD-001-1 that while one or more of the methods provided in MOD-028 through MOD-030 may be used by one party across a system, only one of these methods is to be used for a particular flowgate or for a particular path. |
| **Response:** The SDT agrees and the standard requires that only one method may be used for each Posted Path per timeframe. | | | |
| Constellation Energy Commodities | | ☑ | Neither the standard nor the white paper provides enough background information to explain why the structure is necessary. Without the background information it is difficult to determine why this proposed structure is optimal. |
| **Response:** The SDT has modified this and other MOD Standards to make it clear that the structure used will be the correct and optimal structure. | | | |
| FirstEnergy | | ☑ | MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once and eliminate duplication. |
| **Response:** Based in the first set of comments on MOD-001, the SDT concluded that the best approach to the standards was to split them into multiple standards. | | | |
| MEC Trading | | ☑ | MidAmerican Trading believes that only two methodologies really exist and those are a Rated System Path and the Network Response Methodology. Those that do network response are just monitoring a different set of facilities, studying a different set of contingencies and recalculating using the laws of physics with a different frequency. MidAmerican Trading is also concerned that the standard drafting team is still making most of the requirements fill-in-the-blank requirements and more the the |

| **Question #1** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | requirements should be in MOD-001 and standardized for all methodologies. |
| **Response:** The SDT agrees with MEC Trading that the two primary methodologies for planning and operating the BES are Rated System Path and Network Response Methodology. However, the SDT has determined that in parts of the BES the Transmission Service Providers are using the Flowgate Methodology, which is a modification of the Network Response Methodology. Since these parts of the BES are being planned and operated using the Flowgate Methodology by the Transmission Planners, Transmission Operators and Reliability Coordinators the SDT believes that the Flowgate Methodology is necessary to accurately calculate ATC in that part of the BES.<br><br>The SDT has attempted to eliminate "fill-in-the-blank" requirments where possible. | | | |
| MRO | | ☑ | The MRO agrees with team's decision to structure the standards in this manner but we have some comments about it. We believe the Standards Drafting Team should make it clearer in the MOD-001-1 that while one or more of the methods provided in MOD-028 through MOD-030 may be used by one party across a system, only one of these methods is to be used for a particular flowgate or for a particular path. |
| **Response:** The standard drafting team could not identify a reliability-related reason to limit the number of methods used for a particular flowgate or path. | | | |
| IRC | ☑ | ☑ | We do not have a strong view one way or the other on splitting the former MOD-001 into various standards with some of them each addressing an ATC calculation methodology. However, we have some fundamental disagreements with some of the standards as drafted. Unfortunately, the SAR that proposed the split has not provided the scope and description of what went into the draft standards such as MOD-001, MOD-028, MOD-029 and MOD-030, which in our view should have been posted for review and comments before this and the other MOD standards are drafted.<br><br>Specific to this draft standard, we have a number of concerns and comments which we will list below. |
| **Response:** The SDT had made modifications to the MOD Standards to ensure the IRC and the industry has enough information to allow the reader to determine why the Standards contain certain requirements and structure. | | | |
| ERCOT | ☑ | ☑ | See IRC comments. |
| **Response:** See the response to IRC's comments. | | | |
| IESO | ☑ | ☑ | See IRC comments. |
| **Response:** See the response to IRC's comments. | | | |
| ITC | ☑ | ☑ | This is a qualified yes. The three methodologies will make it easier for the various regions in the country to comply with the standards. A single standard would be best, but it would come at a cost for entities to adapt to the single methodology if they are in an area that would have to implement changes to comply with the chosen methodology. The costs would likely not be prohibitive, however, and FERC could mandate a single methodology if they so chose to. We would prefer MOD-030 as a single standard. As the three methodologies now exist, MOD-030 appears to provide the greatest |

| **Question #1** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | flexibility and accuracy. |
| **Response:** The SDT has modified the standards to provide the industry with consistency and transparency, while keeping the structure of the MOD Standards as clear and simple as possible. While FERC could mandate the use of a single methodology, they have indicated that they will not do so at this time. | | | |
| BPA | ☑ | | However, please clarify that "one standard" is MOD-001. |
| **Response:** BPA is correct in assuming that the SDT meant that the "one Standard" is MOD-001-1 | | | |
| Entergy | ☑ | | Entergy supports this approach. |
| WECC MIC MIS ATC TF | ☑ | | |
| Prague Power | ☑ | | |
| BCTC | ☑ | | |
| Duke | ☑ | | |
| HQT | ☑ | | |
| ISO-NE | ☑ | | |
| Manitoba Hydro | ☑ | | |
| NPCC CP9 RSWG | ☑ | | |
| Piney Creek | ☑ | | |
| PSC SC | ☑ | | |
| SCANA | ☑ | | |
| SOCO Transmission | ☑ | | |
| SERC ATCWG | ☑ | | |

2. This standard and accompanying methodology standards (MOD-028, MOD-029, MOD-030) include requirements on establishing the Total Transfer Capability or Total Flowgate Capability that shall be used as input to the process. With the addition of these requirements for establishing TTC/TFC, do you believe that FAC-012 and FAC-013 should be retired? If "No," please describe what changes, if any, should be made to FAC-012 and/or FAC-013 in the comments area.

**Summary Consideration:** There was no consensus amongst the stakeholders who responded to this question. The drafting team has incorporated and expanded upon the requirements from FAC-012 and FAC-013 and included these requirements in the proposed set of ATC standards. Consequently, the SDT is recommending that Standards FAC-012 and -013 be retired. The SDT has developed its Standards to require that whatever TTC values and assumptions the TSP uses to calculate ATC must be the same TTC values and assumptions the Transmission Planners and Reliability Coordinators use for planning and operation of the BES.

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings.<br><br>FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC. |
| **Response:** The SDT agrees that the FERC has recommended that TTC be addressed in the FAC Standards. The SDT has expanded the SDT membership to incorporate addition team members who are very knowledgeable in calculating TTC and TFC. The SDT has conferred with these new members to determine the best method of developing Standards that will provide the necessary requirements to accurately and clearly calculate TTC and TFC for each methodology, and these new members support retiring FAC-012 and FAC-013. | | | |
| Duke | | ☑ | FAC-012 should be modified to clearly state that the purpose is to provide instructions for calculating transfer capabilities used in regional reliability assessments. The methodologies used for calculating TTC and these transfer capabilities should be similar, but the assumptions will vary due to the different purposes of the calculations. The major difference is that transfer capabilities for use in reliability assessments are generally only calculated once or twice a year for peak season conditions and TTCs are generally calculated more frequently. Additionally, the transfer capabilities used in reliability assessments should use assumptions reflecting a "worst case" scenario, whereas the |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | assumptions used for calculating TTC should reflect the best forecast of conditions for the particular time period the TTC is being calculated |
| **Response:** The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability Coordinators for planning and operations of the BES. | | | |
| IRC | | ☑ | Owing to the various concerns we have over MOD-001, MOD-028 to MOD-030, we are unable to determine at this time whether or not FAC-012 and FAC-013 can or cannot be retired until we see the more refined versions of the MOD standards. |
| **Response:** The drafting team has refined all of the standards based on stakeholder comments, NAESB comments, and feedback from FERC staff. The drafting team believes the revised standards incorporate and expand upon the requirements in FAC-012 and FAC-013. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See the response to IRC's comments. | | | |
| IESO | | ☑ | See IRC comments. |
| **Response:** See the response to IRC's comments. | | | |
| MEC | | ☑ | FAC-012 and FAC-013 need to be revised as necessary to cover other reliability needs for Transfer Capability measurements such as for unusual operating conditions that do not need to be the basis for commercial offerings. |
| **Response:** The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability Coordinators for planning and operations of the BES. | | | |
| MRO | | ☑ | FAC-012 and FAC-013 need to be revised as necessary to cover other reliability needs for Transfer Capability measurements such as for unusual operating conditions that do not need to be the basis for commercial offerings. |
| **Response:** The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability Coordinators for planning and operations of the BES. | | | |
| MEC Trading | | ☑ | FAC-012 and FAC-013 should be revised as necessary to clearly state that they are for covering the reliability needs for Transfer Capability measurements such as for unusual operating conditions to help establish operating guides or provide guidance to the operators and that are not the basis for commercial offerings or the for the decisions to accept or deny transmission service requests. |
| **Response:** The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability | | | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Coordinators for planning and operations of the BES. | | | |
| NPCC CP9 RSWG HQT | ☑ | ☑ | Are FAC-012 and FAC-013 intended to be for only interfaces where transmission service is sold? If not, and these standards are intended to cover the establishment of intra-area interfaces, then the retirement of these standards would be leaving a gap that is not covered by other standards. |
| **Response:** The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability Coordinators for planning and operations of the BES. | | | |
| ITC | ☑ | ☑ | We never thought FAC-012 or -013 should apply to ATC calculations. They are a system "test" and not a rigorous calculation of TTC for sale of transmission service. |
| **Response:** The SDT has developed Standards that will ensure that what ever TTC values and assumption that are used by the TSP to calculate ATC will be the same TTC values and assumptions used by the Transmission Planners and Reliability Coordinators for planning and operations of the BES. | | | |
| Entergy | ☑ | | Yes, FAC-012 and FAC-013 can be retired after requirements for TTC/TFC methodologies are included in these standards. |
| FirstEnergy | ☑ | | FAC-012 and 013 are similar in scope to MOD-001 and should be retired once MOD-001 is revised. |
| Manitoba Hydro | ☑ | | |
| WECC MIC MIS ATC TF | ☑ | | |
| Prague Power | ☑ | | |
| Piney Creek | ☑ | | |
| PSC SC | ☑ | | |
| SCANA | ☑ | | |
| SOCO Transmission | ☑ | | |
| SERC ATCWG | ☑ | | |

3. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please explain why in the comments area.

**Summary Consideration:** There was no consensus amongst the stakeholders who responded to this question that the proposed standard identified the correct set of functional entities. Several stakeholders indicated that the Reliability Coordinator and Planning Coordinator should not be assigned requirements. Upon further review of the functional model, the SDT agrees the Reliability Coordinator and the Planning Coordinator do not have a role in the ATC process and the Transmission Operator does have a role in coordinating ATC with the Transmission Service Provider. Based on these comments and observations, the drafting team changed the applicability section of the standard to delete the Planning Coordinator and Reliability Coordinator and to add the Transmission Operator.

| **Question #3** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | ☑ | First, the "Applicability" section uses the term "Planning Coordinator" which is not a defined term in the NERC Glossary. If the NERC Team intends it use, it should become a defined term.<br>Second, where the term Planning Coordinator is used, WECC queries whether or not the more accurate entity would be the Transmission Planner.<br>Third, this Standard should not apply to the Reliability Coordinator. The RC should be removed from R1 and R2. (See comments appended.) |
| **Response:** The Reliability Coordinator and the Planning Coordinator have been removed from the Applicability section. | | | |
| APPA | | ☑ | MOD-001 if written correctly will detail has the Transmission Service Provider will:<br>1) acquire the necessary data to calculculate the ATC;<br>2) the frequency of calculation;<br>3) the posting of values of the ATC, ATC formula components, and the assumptions use to obtain the values of the the ATC formula components. ---- The other Applicable Functions will be in supporting Standards for TTC/TFC, CBM, TRM, and ETC. |
| **Response:** The SDT agrees with statements 1) and 2) and has changed the Standard to reflect this observation. The posting requirements are NAESB's responsibility and the drafting team has been working closely with NAESB to ensure the posting of the pertinent information. | | | |
| BCTC | | ☑ | ATC related standards should be applicable only to entities who have the obligation to provide non-discriminatory transmission service, that is the Transmission Service Providers. |
| **Response:** The SDT agrees MOD-001 should apply to the TSP, but also notes that the Functional Model assigns the Transmission Operator responsibility for coordinating ATC with the TSP and the team changed the Standard to reflect these observations. | | | |
| BPA | | ☑ | "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority. |
| **Response:** The SDT has removed the Planning Coordinator from the Applicability section of the standard. | | | |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| IRC | | ☑ | The RC and PC do not have a role in MOD-001 as they are neither responsible for calculating ATC, nor are they responsible for implementing or agreeing to a method for use in calculating ATC. |
| **Response:** Upon further review of the functional model, the SDT agrees the RC and the PC do not have a role in the ATC process and has changed the Standard to reflect this observation. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See the responses to the IRC's comments. | | | |
| IESO | | ☑ | See IRC comments. |
| **Response:** See the responses to the IRC's comments. | | | |
| ITC | | ☑ | We understand that certain areas of the country may want Reliability Coordinators to be responsible entities, perhaps because they wear both the RC and TSP hat, but this is not a reason to include them. In the MISO footprint, it makes no sense to include the RC. However, we do think that a list of applicable entities should include the "Transmission Planner," as has been indicated in MOD-004 and MOD-008. This is more appropriate than the RC. As written, several entities are excluded from the applicability statement. |
| **Response:** The SDT agrees that the RC should not be included and has changed the Standard to reflect this observation. The Standard Drafting Team has limited the applicability of these standards to ATC values calculated up to 13 months and therefore does not believe the Transmission Planner is applicable. The drafting team did add the Transmission Operator as a responsible entity, as the Transmission Operator is identified in the Functional Model as having a responsibility for coordinating ATC with the Transmission Service Provider. | | | |
| ISO-NE | ☑ | | While the RC and the PC do not calculate ATC, they are responsible for calculating TTC which is a direct input to the ATC calculation. Since the selection of the TTC methodology will determine which ATC standard is utilized by the TSP, it is appropriate for the RC and the PC to be applicable entities in this standard. While it is not specifically stated in R1 and R2 that the RC and PC are involved solely because of their involvement in TTC, the MOD-028, MOD-029 and MOD-030 clearly deliniate the responsibility for those entities. |
| **Response:** The Standard Drafting Team has limited the applicability of these standards to ATC values calculated up to 13 months, and therefore has removed the Planning Coordinator and Reliability Coordinator from the Applicability. | | | |
| Piney Creek | ☑ | | You may desire to 'reference' the generator rating standards (FAC-005-0/FAC-009-1) that requires submission of facility ratings where needed. |
| **Response:** The Standards now include references to facility ratings as required in the FAC standards. Note that FAC-005 is retired – it was replaced with FAC-008 and FAC-009. However, the Standard Drafting Team hesitates to reference specific standards because the specific requirements may move to a different standard or the standard may be renumbered. | | | |
| Prague Power | ☑ | | |
| Constellation Energy Commodities | ☑ | | |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Duke | ☑ | | |
| Entergy | ☑ | | |
| FirstEnergy | ☑ | | |
| HQT | ☑ | | |
| Manitoba Hydro | ☑ | | |
| MEC | ☑ | | |
| MEC Trading | ☑ | | |
| MRO | ☑ | | |
| NPCC CP9 RSWG | ☑ | | |
| PSC SC | ☑ | | |
| SOCO Transmission | ☑ | | |

4. Do you agree with the calculation frequency and schedule in R5.? If "No," please explain and suggest any alternatives you believe to be appropriate in the comments area.

**Summary Consideration:** There was no consensus amongst the stakeholders who responded to this comment. Several modifications were suggested, but no single proposed modification was supported by a majority of the stakeholders.
The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system, and has retained the calculation schedule, but eliminated the specific times since some stakeholders indicated that having all entities update ATC at the same time has some technical challenges See the changes below – note that in the revised standard, this requirement has been re-numbered and is Requirement R9.

Each Transmission Service Provider ~~that calculates ATC~~ shall update ATC, at a minimum, ~~recalculate ATC at~~ on the following frequency:

For hourly ATC, once per hour~~, (on the hour), for the next 168 hours.~~

For daily ATC, once per day~~, (at midnight prevailing time the day previous), for thirty days.~~

For weekly ATC, once per day~~, (at midnight prevailing time on the Monday previous), for four weeks.~~

For monthly ATC, once per month~~, (at midnight prevailing time on the first day of the month previous) for 13 months.~~

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | ☑ | 1) The minimum calculation requirements should require recalculation during regular business hours, as opposed to every day at midnight.<br><br>2) Currently, most of WECC utilizes OATI. If the OATI system is required to recalcuate the entire West at a single moment, that system may not be capable of doing the calcuations. Since OATI currently recalulates continuously as variables change, can the NERC Team draft language to allow for a recalculation or reposting within an hour as opposed to all entities doing so at a specified moment?<br><br>3) The WECC Team in general has the following question of interpretation for the NERC Team. To the extent the WECC Team does not understand "how" tocomply with the requirements, it would seem the requirements are either overly vague or unenforceable as written. Please answer the appended question and rewrite for clarity.<br><br>The question revolves around the calculation frequency and required recalculation (forecasts?) of ATC going forward:<br>A. Does this recalculation requirement in any way mandate that transmission providers should adjust (hourly, daily, etc) ATC in response to network load variations? |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Taken as currently written, this standard could be interpreted to require TPs to (1) forecast load variations, by path, by day (or hour), (2) reduce network (and possibly PTP) load reservations, "freeing up" future daily (or hourly if offered) ATC and (3) sell firm capacity going forward in response to a load forecast on a path by path basis.<br><br>This is not a reasonable expectation for TPs to be 100% accurate in load forecasts, and this standard, if making the requirement outlined in the above interpretation, should be clarified to require TPs to update ATC only in response to future capacity sold, and not be required to reduce network reservations as a response to load forecasts to allow future short term firm sales on a daily (or hourly if offered) basis.<br><br>In the interpretation outlined above, if the transmission provider (or LSE) is incorrect in load forecasts, and the TP has sold short term firm in these "freed up" ATC periods, it would restrict network (and PTP) customers from scheduling up to their "before the hour" rights without curtailment. |
| **Response:** 1) The need to change the ATC during the off duty hours due to a change in one of the components needs to be covered. Procedures need to be in place where this action will be preformed during non-business hours.<br>2) The SDT has modified the requirement such that recalculations are done as needed, rather than at a specified time, but the revised requirements include a "minimum" time.<br>3A (1) (2) (3)) The SDT revised the Standard to remove this vagueness and confusion. | | | |
| APPA | | ☑ | The Requirement 5 should set the Maximum amount of time between calculations. The way it is written is that the Requirement sets a Minimum amount of time between calculations. What if an entity updated the Daily before the 24 hours was up; they would be non-compliant. In addition, since hourly covers the next 168 hours, Daily or Weekly calculations will be overlaping each other, one should be omitted. Note TVA's posted method, while they mention Daily and Weekly, they only post Daily for 30 days. |
| **Response:** The SDT has modified these statements to ensure that there will be no confusion. | | | |
| BCTC | | ☑ | The calculation frequency is a business practice and should not be part of NERC standards. |
| **Response:** The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system. | | | |
| BPA | | ☑ | The minimum calculation requirements should mandate recalculation during regular business hours, as opposed to every day at midnight. We suggest leaving the final determination of the proper time for ATC/AFC calculation updates to NAESB, as this is a business practice issue.<br>Additionally, R5.5. should be added to address the calculation frequency for annual ATC/AFC values. |
| **Response:** The SDT has removed the requirement to recalculate at a specified time. The Standard Drafting Team has limited the calculations to those that are generally required to be posted, as annual values often have more rigorous evaluation processes due to the increase in available time. | | | |

| **Question #4** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Constellation Energy Commodities | | ☑ | Specifically, R5.4: a minimum of "once a month" is not enough to facilitate commercial activities. Frequency should be "once a day" with a waiver if the inputs to the model have not changed "significantly" from the previous day. Also, what is the minimum frequency for yearly service? |
| **Response:** The SDT has increased the frequency to once per week. The Standard Drafting Team has limited the calculations to those that are generally required to be posted, as annual values often have more rigorous evaluation processes due to the increase in available time. | | | |
| Duke | | ☑ | R5 should be modified to include yearly ATC. |
| **Response:** The standard does not preclude the determination of a yearly ATC. If an entity wants to have a Yearly ATC then the entity can utilize monthly ATC, TTC, calculations to extend for as many months as an entity wants, i.e. 24 months, 36 months, 48 months, and so-on. AIf a request for transmission service beyond one year is denied, the entity requesting that transmission service can request that the TSP run studies and the transmission request will not be part of the ATC request, but a long-term request. | | | |
| Entergy | | ☑ | Calculation frequency should be linked with the change in elements of ATC that impact ATC. For example Monthly ATC should not be only calculated once a month, rather it should be recalculated when any reservation impacting the Monthly ATC is confirmed, this could be a Daily or Weekly reservation. If a reservation that impacts the Monthly reservation is confirmed on second day of the month, and Monthly ATCs are not recalculated till first day of the next month, the Monthly ATC values for the impacted period will remain inaccurate for the remaining entire month. Recalculation frequency should be included in NAESB business Practice Standard rather than in reliability standard. |
| **Response:**<br>The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system, and found it difficult to define for all paths on all systems what would produce a "significant" change in ATC values. | | | |
| HQT<br>ISO-NE | | ☑ | (1) Language needs to be clear that TSPs only have to calculate ATC for durations of service that they offer.<br>(2) Regarding the frequency of the updates; it should be clear that if no inputs have changed that no recalculations are required. For example, for those entities that update ATC automatically based on receipt of service requests or a change in TTC, it would be burdensome to 'recalculate' on this stated frequency with no added value.<br>(3) Regarding the timing of the updates; Suggest replace 'at' with 'no later than' so that the auditing aspect of this requirement is reasonable. Entities would be allowed to have calculated that data at any time prior to this required time point. Required timing of updates to be 'at' a specific time creates an auditing trap. For example, how long does it take to perform a set of ATC calculations? Is this requiring that calculations be started at this time or completed by this time? Knowing when the calculations are completed will also provide a known time point for the posting requirements to be developed by NAESB. |
| **Response:** Note that the already approved MOD-001 requires that ATC be determined and posted at specified intervals, so | | | |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| this is not a major revision to existing requirements.<br>The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system.<br>The SDT changed the wording for the timing of the updates so that an auditing program may be conducted without undue burden on the TSP by eliminating the specific posting times. | | | |
| MEC | | ☑ | In practice in the industry, the calculation frequency is not consistent across all methodologies. In some cases the times for posting and the frequency of recalculations are slower to allow for time to validate the values calculated. I believe that reliability will suffer if validation is eliminated so as to meet a target that is set by the Standard.<br><br>Further, the frequency requirements should be consistent with currently filed FERC Operating Agreements. Therefore, I suggest that whatever frequency requirements are provided that they be qualified with allowances that "other frequency recalculation and posting times are allowed provided the Transmission Provider coordinates such frequencies and posting times with its neighbors and documents the valid reasons for adopting such frequencies". Also, alternatively or in addition, the Standards Drafting Team should indicate that "if the Transmission Provider has filed FERC Operating Agreement(s) that provides for alternative recalculation frequencies and/or posting times that those frequencies and/or posting times are acceptable."<br><br>Also, I do not believe that separate weekly posting are required. If a Transmission Provider provides enough daily postings into the future to meet weekly needs, that these daily postings should be adequate. The way the standard is written now it appears as if weekly postings are required. The Standards Drafting Team should clarify that the frequencies and posting for weekly are only if the Transmission Provider posts separate weekly quantities. (The FERC requires hourly, daily, and monthly postings so no such clarification is required for the other frequencies and posting times listed in the draft standard.)<br><br>Also, the posting times in particular seem to be too inflexible particularly for longer period offerings. Why does everyone have to post the daily quantities at midnight and only midnight? MAPP posts daily quantities at 10 a.m. on the previous day which seems adequate to me. I suggest that, at a minimum, the posting team needs to either make these posting times which the Transmission Provider may post at or before, or else replace the posting times with an acceptable window for posting. For example, either the daily quantities can be posted "on or before midnight" or alternatively "on the previous day" if the SDT believes that posting too early is as big a problem as posting too late. |
| **Response:**<br>The SDT has modified the Standard to allow for additional flexibility.<br><br>If an entity wants to also calculate a Yearly and Weekly the Standard will not prevent the entity from posting this calculation. | | | |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| The SDT has modified the Standard to give the TSP flexibility by eliminating the specific posting times.<br><br>The SDT removed the requirement for weekly posting in support of your comments. | | | |
| MRO | | ☑ | In practice in the industry, the calculation frequency is not consistent across all methodologies. In some cases the times for posting and the frequency of recalculations are slower to allow for time to validate the values calculated. The MRO believes that reliability will suffer if validation is eliminated so as to meet a target that is set by the Standard.<br><br>Further, the frequency requirements should be consistent with currently filed FERC Operating Agreements. Therefore, the MRO suggests that whatever frequency requirements are provided that they be qualified with allowances that "other frequency recalculation and posting times are allowed provided the Transmission Provider coordinates such frequencies and posting times with its neighbors and documents the valid reasons for adopting such frequencies". Also, alternatively or in addition, the Standards Drafting Team should indicate that "if the Transmission Provider has filed FERC Operating Agreement(s) that provides for alternative recalculation frequencies and/or posting times that those frequencies and/or posting times are acceptable."<br><br>Also, the MRO does not believe that separate weekly posting are required. If a Transmission Provider provides enough daily postings into the future to meet weekly needs, that these daily postings should be adequate. The way the standard is written now it appears as if weekly postings are required. The Standards Drafting Team should clarify that the frequencies and posting for weekly are only if the Transmission Povider posts separate weekly quantities. (The FERC requires hourly, daily, and monthly postings so no such clarification is required for the other frequencies and posting times listed in the draft standard.)<br><br>Also, the posting times in particular seem to be too inflexible particularly for longer period offerings. Why does everyone have to post the daily quantities at midnight and only midnight? MAPP posts daily quantities at 10 a.m. on the previous day which seems adequate to the MRO. The MRO suggests that, at a minimum, the posting team needs to either make these posting times which the Transmission Provider may post at or before, or else replace the posting times with an acceptable window for posting. For example, either the daily quantities can be posted "on or before midnight" or alternatively "on the previous day" if the SDT believes that posting too early is as big a problem as posting too late. |
| **Response:**<br>The SDT has modified the Standard to allow for additional flexibility. | | | |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| If an entity wants to also calculate a Yearly and Weekly the Standard will not prevent the entity from posting this calculation. The SDT has modified the Standard to set the latest time to post, and give the TSP flexibility by eliminating the specific posting times.<br>The SDT removed the requirement for weekly posting in support of your comments. | | | |
| NPCC CP9 RSWG | | ☑ | (1) Language needs to be clear that TSPs only have to calculate ATC for durations of service that they offer.<br>(2) Regarding the frequency of the updates; it should be clear that if no inputs have changed that no recalculations are required. For example, for those entities that update ATC automatically based on receipt of service requests or a change in TTC, it would be burdensome to 'recalculate' on this stated frequency with no added value.<br>(3) Regarding the timing of the updates; Suggest replace 'at' with 'no later than' so that the auditing aspect of this requirement is reasonable. Entities would be allowed to have calculated that data at any time prior to this required time point. Required timing of updates to be 'at' a specific time creates an auditing trap. For example, how long does it take to perform a set of ATC calculations? Is this requiring that calculations be started at this time or completed by this time? Knowing when the calculations are completed will also provide a known time point for the posting requirements to be developed by NAESB. |
| **Response:** The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system. The SDT has changed the wording for the timing of the updates so that an auditing program may be conducted without undue burden on the TSP by eliminating the specific posting times. | | | |
| SCANA | | ☑ | Recalculation of TTC/TFC should be due to a change in system conditions that warrant a recalculation. Recalculation of ATC/AFC should be due to a change in one or more of the components included in the ATC/AFC calculation formula (including TTC/TFC). No set frequency should be set for these calculations. |
| **Response:** The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system, and found it difficult to define for all paths on all systems what would produce a "significant" change in ATC values. Note that the already approved MOD-001 requires that ATC be determined and posted at specified intervals, so this is not a major revision to existing requirements. | | | |
| SOCO Transmission | | ☑ | The requirement is too prescriptive with respect to the times that the calculations need to be performed. Other processes (e.g., ramps, schedule updates, etc) are also being performed across the top of the hour. Each TSP should be allowed the flexibility to set a more appropriate time for recalculations.<br>This requirement should also not require a recalculation of ATC unless the one of the components of the ATC equation changes. |
| **Response:** The SDT agrees that the timing requirements are too prescriptive and has removed the requirement to calculate at a specified time. However, the SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system, and found it difficult to define for all paths on all systems what would produce a "significant" | | | |

| **Question #4** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| change in ATC values. Note that the already approved MOD-001 requires that ATC be determined and posted at specified intervals, so this is not a major revision to existing requirements. | | | |
| SERC ATCWG | | ☑ | Calculation frequency should be based on changes in system conditions or granting of additional transmission service. Calculations based on a set frequency would not improve reliability. |
| **Response:** Note that the already approved MOD-001 requires that ATC be determined and posted at specified intervals, so this is not a major revision to existing requirements. The SDT believes consistency in calculation timing is important to ensuring coordinated and reliable operation of the system, and found it difficult to define for all paths on all systems what would produce a "significant" change in ATC values. | | | |
| IRC | | ☑ | The calculation frequency is not consistent across all methodologies. The frequency should allow for time to validate the values calculated. It may not be consistent with currently filed FERC Operating Agreements, which is not a minimum requirement for the whole industry. |
| **Response:** The Standard Drafting Team has made the minimum frequency for calculating ATCs more consistent, but there are technical reasons why different methodologies should have different requirements for updating TTCs or AFCs. | | | |
| ERCOT | ☑ | ☑ | ERCOT does not perform these calculations since these concepts are not used within ERCOT. See IRC comments submitted by Charles Yeung. |
| **Response:** ERCOT may wish to submit a request for a Regional Difference. See the response to the IRC comments. | | | |
| FirstEnergy | ☑ | | R5 should require recalculation of ATC as interchange schedules or transmission reservations change. |
| **Response:** The SDT felt "as interchange schedules or transmission reservations change" would be too vague to measure. Note that the already approved MOD-001 requires that ATC be determined and posted at specified intervals, so this is not a major revision to existing requirements. | | | |
| IESO | ☑ | | We generally agree. |
| ITC | ☑ | | |
| Prague Power | ☑ | | |
| MEC Trading | ☑ | | |
| Piney Creek | ☑ | | |
| PSC SC | ☑ | | |

5. Do you agree the information to be included in the "Available Transfer Capability Implementation Document" that will be made publicly available (as required in R3) is appropriate and sufficient? If "No," please explain why in the comments area.

**Summary Consideration:** Most stakeholders did indicate that the information listed in Requirement 3 is appropriate and sufficient. There were some stakeholder suggestions to clarify the standard to ensure that only information pertaining to Posted Paths or networks is required and other comments suggesting specific additions to the sub-requirements in R3. Based on stakeholder comment, the SDT modified R1 so it is only applicable to the Transmission Operator and the scope of Transfer Capabilities has been clarified as being limited to those for each Posted Path within the Transmission Operator's Planning Coordinator's Area. The SDT modified R3 to add a sub-requirement to describe any third party allocation methodlogies in the ATCID. The changes are highlighted below:

**R1.** Each Transmission Operator ~~Service Provider, and its associated Planning Coordinators and Reliability Coordinators,~~ shall ~~agree upon and implement~~ select one or more of the ATC methodologies ~~specified in Reliability Standard MOD-028, MOD-029, and MOD-030~~ (Area Interchange methodology, Rated System Path methodology, or Flowgate methodology) for use in determining Transfer Capabilities of those Facilities for each Posted Path per time period within its Planning Coordinator's planning area. ~~under the tariff administration of that Transmission Service Provider~~.

**R3.** Each Transmission Service Provider shall ~~make publicly available~~ prepare and maintain an "Available Transfer Capability Implementation Document" (ATCID) that includes, at~~s~~ a minimum, the following information:

**R3.1** Information describing ~~which methodology (or methodologies) has been selected and~~ how the selected methodology (or methodologies) has (have) been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC calculations may be validated.

**R3.2** A description of the manner in which the Transmission Service Provider will account for counter-flows or counter schedules.

**R3.3** The identity of the Planning Coordinator and ~~Reliability Coordinator~~ Transmission Operator associated with each Facility under the Transmission Service Provider's tariff.

**R3.4** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer capability.

**R3.5** The identity of the Transmission Service Providers from which it receives data for use in calculating transfer capability.

**R3.6** Third party allocation methodologies.

| Question #5 |
|---|

| Commenter | Yes | No | Comment |
|---|---|---|---|
| APPA | | ☑ | Available Transfer Capability Implementation Document (ATCID) is redundant should not be made a requirement of the TSP. The ATC is just the algebraic sum of the four components; TTC, ETC, CBM, and TRM. What ever method is used to calculate the TTC, i.e. Flow Gate, Rated System Path, or Network is determined by the planners; RC or TOP and the assumptions will accompany the TTC/TFC values and be posted. The complete description of the ATC calculation is contained in the assumptions of the other components, CBM, TRM, and ETC, which will be posted on the OASIS or other electronic means. |
| **Response:** The SDT has reviewed and modified this Standard to ensure that any possibility of redundancy is removed. | | | |
| BPA | | ☑ | R3.1. should read "… the results of the ATC/AFC calculations may be validated."<br>R3.6. should be added to clarify that the ATCID must only include information pertaining to Posted Paths or Flowgates, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. |
| **Response:**<br>R3.1 - FERC requires that ATC be calculated so there is no reason to add AFC to the requirement.<br><br>R3.6 - The proposed modification was made and is reflected in the revised R1 of the standard. The revised R1 clarifieds that the ATC methodologies are for use in determining Transfer Capabilities of the Faciities for each 'Posted Path . . . ' in support of your suggestion. | | | |
| Constellation Energy Commodities | | ☑ | Need to include more details as to how transmission service request are modeled. |
| **Response:** The SDT has included additional detail in MOD-028 and MOD-030, as these are the methodologies that require modeling of transmission service reservations. | | | |
| Duke | | ☑ | Need to add another requirement that describes the manner in which the Transmission Service Provider will account for allocation of firm transmission capacity (i.e. reciprocal flowgate allocation). |
| **Response:** The SDT has added a sub-requirement to include third party allocation methodologies in the ATCID. | | | |
| Entergy | | ☑ | R 3.5 requires identifying only TSPs from which data is received. In practice, TSP may receive data from entities other than TSP's such as PSEs, Generator Operators etc. for calculating transfer capability. Entergy suggests that TSP should identify all suppliers of data in ATCID for calculation of ATCs and not only other TSPs. |
| **Response:** While the drafting team agrees that other information is obtained and used in the determination of ATC, the intent of this requirement is to identify the other transmission service providers with which the TSP is coordinating. | | | |
| IRC | | ☑ | We do not know what this Available Transfer Capability Implementation Document (ATCID) is intended to provide and serve. Is this a document that resembles or replaces the existing Regional ATC Methodology document? If so, there is much more information to be provided. For example, coordination with neighboring TSPs on ATC calculation, interface definitions, path names, etc.<br><br>Notwithstanding the above concerns, we do not understand why the RC and the PC need to be |

| **Question #5** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | identified in R3.3 but not the TOP. |
| **Response:** The ATCID is intended to replace the Regional ATC Methodology documents. The ATCID can include more information than is required. Note that as long as the ATCID complies with the standard, it can effectively be identical to the Regional ATC Methodology document.<br><br>We have replaced the Reliability Coordinator with the Transmission Operator. | | | |
| IESO | | ☑ | See IRC comments. |
| **Response:** See reply to IRC comments | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See reply to IRC comments submitted by Charles Yeung | | | |
| FirstEnergy | | ☑ | R3 gives the TSP a lot of leeway in how it implements the calculations that it performs under this standard. R3.1 is not specific enough to meet the intent of 693-1057, additional detail on required elements is needed to ensure that adequate data is exchanged to enable the duplication and verification of the calculations for validation. |
| **Response:** There is a need for more detail, either in the standards themselves or in the ATCID. The SDT modified the Standard to address this issue – see the expanded list of data to be exchanged in Requirement 10 (was R6 in Draft 2) of the third draft of this Standard. | | | |
| Manitoba Hydro | | ☑ | No direct instruction for informing public of ongoing ATC values is provided, although this process is an implied result of adhering to R3.1 and R5. |
| **Response:** MOD-028, 029, and 030 specify that this information must be formatted for posting. The NAESB business practices will specify that ongoing ATC values must be provided to the public via OASIS. | | | |
| MEC Trading | | ☑ | The document should also include a technical explanation of how transmission service requests are being evaluated. |
| **Response:** The SDT has determined that the evaluation of transmission service request is determined by tariffs, contracts, or other type of agreements. The rules of the evaluation of transmission service request should be determined by the rules made by NAESB. Industry also indicated that evaluation and approval of transmission requests is not within the scope of the drafting team. | | | |
| ITC | ☑ | ☑ | The more transparency there is in the process (except for commercially sensitive data), the better the process will be. |
| **Response:** The SDT agrees, and notes that NAESB sets business practices for additional transparency. | | | |
| WECC MIC MIS ATC TF | ☑ | | The WECC Team concurs that the stated content of the ATCID is appropriate. However, the term "ATCID" is used as a defined term without a definition. It is also used in multiple other standards. It should either be a defined term in the NERC Glossary or, at minimum, must be cross referenced from all other standards back to this standard. |
| **Response:** The SDT has drafted a definition of ATCID for the glossary. | | | |

| Question #5 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Prague Power | ☑ | | |
| BCTC | ☑ | | |
| HQT | ☑ | | |
| ISO-NE | ☑ | | |
| MEC | ☑ | | |
| MRO | ☑ | | |
| NPCC CP9 RSWG | ☑ | | |
| Piney Creek | ☑ | | |
| PSC SC | ☑ | | |
| SCANA | ☑ | | |
| SOCO Transmission | ☑ | | |
| SERC ATCWG | ☑ | | |

2. Do you agree the information to be exchanged with requesting entities (as required in R6) is appropriate and sufficient? If "No," please explain why in the comment area.

**Summary Consideration:** The SDT has modified the Standard to specify the data is to be used in the ATC calculation. Distribution of this information to Transmission Customers should be addressed through the NAESB business practice standards process. The changes are in Requirement 10 of the revised standard and are highlighted below:

R10. Within fourteen calendar days of a request of any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator, ~~E~~each Transmission Service Provider shall begin to make the following information available on the schedule specified by the requester (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider), unless another request already specifies data on a more frequent basis, to all ~~to any~~ ~~requesting~~ Transmission Service Providers, Planning Coordinators, ~~Transmission Planner,~~ Reliability Coordinators, and Transmission Operators, ~~or other party with a demonstrated reliability need~~ current versions of the following data as requested in electronic format for use in ATC calculations, for up to 13 months into the future (subject to security and confidentiality requirements):

R10.1 Expected generation and Transmission outages, additions, and retirements

R10.2 Peak Load forecasts.

~~Generation dispatch, in the form of dispatch order, participation factors, or block dispatch~~.

R10.3 Unit commitments and dispatch orders, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:

- Dispatch order
- Participation factors
- Block dispatch

~~Planned and unplanned transmission outages.~~

~~Planned and unplanned generation outages.~~

R10.4 Firm and non-firm Network Integration Transmission Service details

R10.5 Confirmed firm and non-firm Transmission Reservations.

R10.6 Grandfathered firm and non-firm contracts

R10.7 Firm roll-over rights

R10.8 Any firm and non-firm adjustments to reflect parallel path impacts

R10.9 Power flow models and underlying assumptions.

R10.10 Contingencies, provided in one or more of the following formats:

- A list of Elements

- A list of Flowgates
- A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider

10.11 Facility Ratings.

10.12 Counterflows

~~ATC recalculation frequency and times.~~

10.13 Values of ATC, ETC, CBM, TRM, and TTC for all Posted Paths

10.14 Values of TFC and AFC for any Flowgates considered by the Transmission Service Provider when selling Transmission service

~~Transmission Reservation impact modeling identification, such that a source-to-sink analysis of power flow impacts could be undertaken.~~

10.15 Source and sink identification and mapping to the model.

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | ☑ | See 9.D. below.<br>9.D. -- There is a concern that where two entities have not selected the same methodology, and where one requests data from the other, the requesting entity must still provide the requested data even if that data is not utilized in the methodology of the providing entity. In other words, an entity cannot be allowed to refuse data provision simply because that entity doesn't use such data in its selected methodology. The Requirement as drafted does not make this clear. |
| **Response:** The SDT believes that it is important for the requesting entity to have the information necessary for its calculation. The requirement uses the word, 'shall,' meaning that the data must be provided or the responsible entity is non-compliant. | | | |
| Prague Power | | ☑ | The entities calculating ATC should also be required in Requirement R6 to include and honor third party flowgate/path limitations in their ATC calculations if that data is provided by affected third parties. |
| **Response:** The SDT has included this concept in MOD-028 – Area Interchange Methodology ( R2.7) and MOD-030 – Flowgate Methodology ( R2.1.3) | | | |
| Constellation Energy Commodities | | ☑ | Need to include Transmission Customers as an entity. |
| **Response:** Distribution of this information to Transmission Customers should be addressed through the NAESB business practice standards process. | | | |
| Duke | | ☑ | Should specify that the information to be made available is information used in calculation of ATC. Also, need to include flowgate allocation data, identifying any portion of flowgate(s) that have been allocated for firm transmission. |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** The SDT modified the Standard to specify the data is to be used in the ATC calculation. With regard to allocation data, this would only apply to entities within an operating agreement, in which case the data exchange would likely be already required. If not in an operating agreement, entities would not need the allocation data. | | | |
| ITC | | ☑ | We agree that what is asked for is appropriate, but it may not be sufficient. For example, the ratings provided should include "any value used to limit AFC/ATC." Ratings can have time, temperature, and seasonal adjustments. As written, compliance might mean just a single ratings set. This could be handled in the compliance and measures section but additional thought should be given to this section. |
| **Response:** The SDT expects the TSP to share the information used in its processes. Please see the revised standard which requires that much more data be provided to requesting entities. | | | |
| SOCO Transmission | | ☑ | It is unclear why the TSP should exchange ATC recalculation frequency and times in R6.8 when they are prescribed in R5. |
| **Response:** We have removed the requirement to share time and frequency of calculations. | | | |
| SERC ATCWG | | ☑ | R6.9 needs clarification. |
| **Response**: The SDT has modified the Standard to remove this lack of clarity. | | | |
| Entergy | | ☑ | It is not clear how other parties can demonstrate reliability need. In addition, in R6.9, it is not clear what is expected under Transmission Reservation impact modeling identification. If response factors are expected, it should be stated as such, or the term impact modeling identification be defined. |
| **Response:** The "reliability need" issue has been eliminated, as the entities have been explicitly identified.<br>The drafting team eliminated the phrase, 'impact modeling identification' and moved this into R10.15. R10.15 now states, 'Source and sink identification and mapping to the model.' | | | |
| IESO | ☑ | ☑ | Though it is not stated in the requirement, we assume these data are related to ATC calculation. Some of the data do not support reliability need (e.g. time and frequency of ATC calculation), while there may be some that do but not listed. There are also some data that are proprietray information for which consent of the information owner must be sought before they can be disseminated. But until we see a more refined set of standards that better align roles and responsibilities, we are unable to provide any specific inputs to the completeness and appropriateness of the list.<br>In R6.5 – By Transmission Reservations, does the requirement mean both "firm" and "non-firm" reservations?<br>In R6.6 – The requirement should state both power flow models and the underlying modeling assumptions including the modeling of generators in the first-tier control areas.<br>The list of single and multiple element contingencies included in the ATC calculation should also be provided. |
| **Response:** We have removed the requirement to share time and frequency of calculations and have clarified that the data are related to ATC calculations. We recognize the proprietary information concerns; TSPs will be expected to get releases to share this information for reliability reasons. | | | |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Re 6.5. Yes, this means both firm and non-firm.<br>Re R6.6. We have included a statement that underlying modeling assumptions should be provided. Publishing lists of contingencies is required in the individual MOD standards as appropriate. | | | |
| IRC | ☑ | ☑ | Though it is not stated in the requirement, we assume these data are related to ATC calculation. Some of the data do not support reliability need (e.g. time and frequency of ATC calculation), while there may be some that do but not listed. There are also some data that are proprietray information for which consent of the information owner must be sought before they can be disseminated. But until we see a more refined set of standards that better align roles and responsibilities, we are unable to provide any specific inputs to the completeness and appropriateness of the list. |
| **Response:** We have removed the requirement to share time and frequency of calculations and have clarified that the data are related to ATC calculations. We recognize the proprietary information concerns; TSPs will be expected to get releases to share this information for reliability reasons. | | | |
| ERCOT | ☑ | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See response to IRC Comments submitted by Charles Yeung. | | | |
| APPA | ☑ | | The posting that are listed are for TTC, the SDT needs to address the assumptions for the other components. |
| **Response:** The SDT agrees and has updated the standard to address this issue. | | | |
| BPA | ☑ | | Except that R6.8. should read "ATC/AFC recalculation frequency and times." |
| **Response:** The SDT has modified the standard to require consistent calculation frequencies and has therefore removed this requirement. | | | |
| FirstEnergy | ☑ | | Overall R6 addresses data sharing better than it does the uniformity of the data. R6 should specify the time periods and method (electronic?) for sharing the specified data. In addition, it should specify the time period of the data to be shared - future data, past data, or both.<br>As written, R6 leaves too much leeway to meets the stated purpose of promoting the consistent and uniform application and documentation of ATC calculations. Lastly, R6 requires the sharing of data with other parties with a demonstrated reliability need, methods are needed for determining that a reliability need has been demonstrated, who will make this determination, and for resolving conflicts. |
| **Response:** The SDT has modified the standard to clarify the requirements related to the data exchange time and schedule. The "reliability need" issue has been eliminated, as the entities have been explicitly identified. | | | |
| BCTC | ☑ | | |
| HQT | ☑ | | |
| ISO-NE | ☑ | | |
| Manitoba Hydro | ☑ | | |

| Question #6 | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| MEC | ☑ | | |
| MEC Trading | ☑ | | |
| MRO | ☑ | | |
| NPCC CP9 RSWG | ☑ | | |
| Piney Creek | ☑ | | |
| PSC SC | ☑ | | |
| SCANA | ☑ | | |

3. Should the scope of MOD-001 be expanded to include requirements for the evaluation of Transmission Service Requests? Please explain your answer in the comments area.

**Summary Consideration:** Most stakeholders who responded to this question indicated that the scope of MOD-001 should not be expanded to include requirements for the evaluation of Transmission Service Requests. Based on the comments received, we will consider this outside the scope of the SDT's charge. This shall serve as a single response to all opinions offered below.

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | ☑ | Evaluation of Transmission Service Requests is outside the scope of the Order(s) and more appropriately falls into the purview of NAESB as a Business Practice. |
| APPA | | ☑ | What is meant by "evaluation of the transmission service request?" If "evaluation of the transmission service request" is prioritizing the transmission service requests base on a predetermined set of rules, the answer is no. Rules to prioritize transmission service requests are based upon negotiated or regulated terms that are a business decision, not reliability, mean by the evaluation of transmission requests? Evaluation of the transmission service request for reliability issues will be made by TOPs or BAs. |
| BCTC | | ☑ | Evaluation of Transmission Service Requests is a tariff and business issue not a reliability issue. |
| BPA | | ☑ | The evaluation of Transmission Service Requests (TSRs) is outside the scope of FERC's Order 890 directives and there is insufficient time left, prior to the scheduled September 18th posting of these standards for balloting, to draft adequate TSR evaluation standards and provide sufficient industry comment periods. |
| Duke | | ☑ | NAESB should be responsible for business practice standards for evaluation of Transmission Service Requests. The only impact the evaluation of TSRs have on ATC calculations is addressed in MOD-028-1, MOD-029-1 and MOD-030-1. |
| Entergy | | ☑ | Requirements of evaluation of Transmission Service Requests are not a reliability issue and it does not have to be included in NERC Reliability Standards. Once Transmission Service Request is confirmed, regardless of which evaluation process is used, it should be included in ETC as appropriate. If needed, Transmission Service Request evaluation process should be addressed by NAESB Business Practice Standards. |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| HQT | | ☑ | The evaluation of Transmission Service Requests is a Business Practice and should continue to be addressed under NAESB. |
| IESO | | ☑ | See IRC comments. |
| IRC | | ☑ | It'd be best to keep this standard to calculating ATC only. Evaluation of transmission service request belongs to another standard, or even a NAESB businesss practice. |
| ISO-NE | | ☑ | The evaluation of Transmission Service Requests is a Business Practice and should continue to be |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | addressed under NAESB. |
| MEC | | ☑ | Transmission request evaluation is not the subject of this standard. If there are reliability reasons that require a standard that should be the subject of a new SAR and a new Standards Drafting Team. |
| MRO | | ☑ | Transmission request evaluation is not the subject of this standard. If there are reliability reasons that require a standard that should be the subject of a new SAR and a new Standards Drafting Team. |
| NPCC CP9 RSWG | | ☑ | The evaluation of Transmission Service Requests is a Business Practice and should continue to be addressed under NAESB. |
| Piney Creek | | ☑ | This may be desirable if/when TSR's are unable to be fulfilled. |
| SCANA | | ☑ | NAESB Business Practices and OATT requirements should address this. |
| SOCO Transmission | | ☑ | The evaluation of Transmission Service Request is governed by the tariff and should remain so. |
| SERC ATCWG | | ☑ | The MOD standards define the bounds for reliably selling transmission service. Tarriff admin and business practices are based on FERC approved tarriffs that operate within these bounds. |
| PSC SC | | ☑ | |
| Prague Power | ☑ | | A procedure should be established to reconcile differences across seams. |
| FirstEnergy | ☑ | | MOD-001 should include the Transmission Service Request evaluation rules necessary to maintain the relaibility of the Bulk Electric System. |
| ITC | ☑ | | This could be in measures and compliance and not necessarily in the requirements. |
| MEC Trading | ☑ | | ATC values are calculated for the evaluation of Transmission Service. If these processes aren't for the evaluation of TSRs, what are they for? |
| Constellation Energy Commodities | ☑ | | |

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

**Summary Consideration:** Most stakeholders indicated that they were not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement.

- Some entities identified the need for a regional variance, and the drafting team advised these stakeholders it is up to the entity that wants a variance to request that variance.
- Some stakeholders indicated that the specific timing requirements for updating ATC may conflict with tariffs, and the drafting team revised the standard to eliminate the requirements to update ATC at specific times.

One stakeholder indicated a concern that the applicability in the standard needs revision. The SDT has reviewed the functional model and modified the Standard to eliminate the Reliability Coordinator and Planning Coordinator and to add the Transmission Operator as responsible entities. This standard will apply to all entities that are required to calculate ATCs.

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | ☑ | | Requirements within this proposed standard deal with the assumptions that will be required by those functions that determine TTC. |
| **Response:** The SDT has reviewed the functional model and modified the Standard as necessary to clarify the requirements and address any concerns. The applicability of the revised standard does include the Transmission Operator and does not include either the Transmission Planner or the Reliability Coordinator. | | | |
| ERCOT | ☑ | | ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT region. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area Interconnection and there has been no reservation of transmission capacity in ERCOT.<br><br>Available Transfer Capability is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. The ERCOT Interconnection has already moved "beyond" ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therfore both ERCOT and SPP are notified when the DC Tie capability is reduced.<br>Under ERCOT market rules, Transmission Service allows all eligible transmission service customers |

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.<br><br>In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.<br><br>In the current and future ERCOT market design the method of calculating ATC, TTC and the use of CBM and TRM are not applicable to the ERCOT Region. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the Interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance. |
| **Response:** The SDT agrees this is a concern - ERCOT may need to submit a request for a Regional Difference. Note that writing a Regional Difference is the responsibility of the entity that wishes that difference. | | | |
| HQT<br>ISO-NE | ☑ | | The current wording of Requirement 5 contains language that dictates precisely when ATC calculations must occur. There are areas with existing market rules and corresponding tariffs that dictate when publications of data occur (for example - after the clearing of a Day Ahead Market). NERC standards do not have the authority to require wholesale changes to existing market structures. Therefore, the wording of the timing of the required ATC calculations must be more general. |
| **Response:** The Standard has been modified to be more flexible and the specific times for updating ATC have been removed from the revised standard. | | | |

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| ITC | ☑ | | Certain areas of the country have tariffs (such as New England) that were approved by FERC and do not require the sale of transmission service. These areas could be saved a lot of grief by excluding them from these standards. However, they should be required to provide any data to their neighbors (such as their impacts on neighbor system flows) that might impact ATC calculations. |
| **Response:** This standard will apply to all entities that are required to calculate ATCs. Entities may need to submit requests for regional differences if they feel the standard should not apply. | | | |
| MEC Trading | ☑ | | This standard in conjuction with the other MODS (28/29/30) are in direct conflict with FERC order 890 requiring consistency. |
| **Response:** The SDT is attempting to maximize consistency while preserving reliability. In the future, please be more specific in identifying any specific conflicts. | | | |
| NPCC CP9 RSWG | ☑ | | The current wording of Requirement 5 contains language that dictates precisely when ATC calculations must occur. There are areas with existing market rules and corresponding tariffs that dictate when publications of data occur (for example - after the clearing of a Day Ahead Market). NERC standards do not have the authority to require wholesale changes to existing market structures. Therefore, the wording of the timing of the required ATC calculations must be more general. |
| **Response:** The Standard has been modified to be more flexible and the specific times for updating ATC have been removed from the revised standard.. | | | |
| IRC | | ☑ | Not aware of any conflicts but it should be pointed out that some entities do not provide physical transmission services. Hence, these standards or some of the requirements in these standards may not apply. |
| **Response:** This standard will apply to all entities that are required to calculate ATCs. Entities may need to submit requests for regional differences if they feel the standard should not apply. | | | |
| IESO | | ☑ | See IRC comments. |
| **Response:** See response to IRC Comment | | | |
| WECC MIC MIS ATC TF | | ☑ | |
| Prague Power | | ☑ | |
| BCTC | | ☑ | |
| Duke | | ☑ | |
| Entergy | | ☑ | |
| MEC | | ☑ | |
| MRO | | ☑ | |

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Piney Creek | | ☑ | |
| PSC SC | | ☑ | |
| SCANA | | ☑ | |
| SOCO Transmission | | ☑ | |
| SERC ATCWG | | ☑ | |
| FirstEnergy | | ☑ | |

5. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-001-1.

**Summary Consideration:** Based on stakeholder comments, the SDT made the following changes:

- Eliminated the reference to "horizons" in R2 to eliminate confusion.
- Modified R1 such that a single entity (Transmission Service Provider) is required to specify the methodology.
- Clarified the entities to which the standard is applicable.
- Added a definition for 'Posted Path'

| Question #9 | |
|---|---|
| **Commenter** | **Comment** |
| WECC MIC MIS ATC TF | A. As to the "Horizons" identified in the draft at R2, the WECC MIC MIS ATC TF opines that there is no singular practice across the industry as to "Horizons"; however those provided by FERC do not generally comport with how the industry uses those terms.<br>The WECC Team suggests that the terms utilized in the draft are at best unclear and at worst not consistent with industry usage. It is suggested these "Horizons" be defined by NAESB as part of the ATC process and that their definitions be established in a manner that best reflects accurate industry usage.<br><br>B. R1. requires TSPs, PCs and RC to "agree upon and implement" a methodology. The standard suggests no remedy if the three parties cannot "agree." The Team suggests the TSP should be the sole entity to select the methodology. The TSP should have a condition precedent to consult with the PC and RC before selection and a condition subsequent to inform the PC and RC of the selection, seek counsel from those entities on how the methodology should be implemented and ultimately inform the PC and RC as to how that selected methodology will be implemented.<br><br>C. R5. Should read:<br>"Each Transmission Service Provider that calculates ATC for a Posted Path shall, at minimum…"<br>This requires the addition of the below FERC approved term as excerpted from 18 CFR 37.6 and as utilitized in NAESB R0-4005 in compliance with Order 889. (References below):<br>Posted Path<br>Posted Path means: 1) Any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. See also: 18 CFR 37.6;<br>http://a257.g.akamaitech.net/7/257/2422/12feb20041500/edocket.access.gpo.gov/cfr_2004/aprqtr/pdf/18cfr37.5.pdf<br><br>D. R6. |

| **Question #9** | |
|---|---|
| **Commenter** | **Comment** |
| | There is a concern that where two entities have not selected the same methodology, and where one requests data from the other, the requesting entity must still provide the requested data even if that data is not utilized in the methodology of the providing entity. In other words, an entity cannot be allowed to refuse data provision simply because that entity doesn't use such data in its selected methodology. The Requirement as drafted does not make this clear. |
| **Response:** A) The SDT has eliminated the reference to "horizons" to eliminate confusion.<br>B) The Standard has been modified to require a single entity to perform the selection.<br>C) The definition as agreed to by NAESB should be adopted as a definition in the NERC Glossary. The drafting team will post this definition with the revised standard.<br>D) The standard clearly states that the Transmission Service Provider 'shall' provide the data. | |
| APPA | The Standard is written much like a Policy and it cannot be determined who is responsible for the different calculations of the components of the ATC. The Standard does not provide the Compliance Monitor or the TSP who calculates the Hourly. Daily, and Monthly ATCs with the necessary requirements to know what is necessary to be compliant. A copy of a Draft MOD-001 that has been written in a Standard Format that will permit the Compliance Monitor and the Applicable Functions to respond to measureable requirements is attached for the SDT review and comments. |
| **Response:** The Standard has been rewritten to remove this problem. Each requirement clearly identifies the responsible entity.<br>**Note –** the proposed standard was not delivered with the comments due to a technical error. The commenter participated in the drafting team meetings and is satisfied that his ideas were considered. | |
| BCTC | A. The horizons described in R2 are not consistent with FAC-010 and FAC-011, which describe the operating horizon and up to one year. These terms are not capitalized and defined anywhere, so I am not going to say that MOD is incorrect. there is a potential for confusion and is communications between the planners and the Transmission Service Providers.<br>B. The requirement "subject to security and confidentiality requirements" in R6 is in conflict with FERC's Standards of Conduct. The TSPs may not provide transmission information discriminatorily.<br>C. R6.9 is unclear. |
| **Response:**<br>**A.**) We have eliminated the reference to "horizons" to eliminate confusion.<br>**B.**) We have modified R6 such that the security and confidentiality applies to only reliability entities, eliminating the conflict.<br>**C.**) We have attempted to clarify 6.9. | |
| BPA | The ATC MODs (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide narrative descriptions of these methodologies.<br>The horizons defined in R2.2. and R2.3. need to be reconciled with the Planning and Operating horizons previously |

| **Question #9** | |
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| **Commenter** | **Comment** |
| | defined by NERC.<br>R5. should be modified to the following:<br>"R5. Each Transmission Service Provider that calculates ATC for Posted Paths or AFC for Flowgates shall, at a minimum, recalculate those ATC/AFCs at the following frequency:<br>R5.1. For hourly ATC/AFC…<br>R5.2. For daily ATC/AFC…<br>R5.3. For weekly ATC/AFC…<br>R5.4. For monthly ATC/AFC…<br>R5.5. For yearly ATC/AFC…"<br>Definitions of the terms "Counter flow" and "Loop flow" are needed, to understand the distinction between the two. |
| **Response:** 1) The SDT agrees with the commenter that additional work needs to be done in clearly distinguishing the methodologies used. We have drafted definitions for the methodologies, which highlight the differences.<br>2.) The SDT has eliminated the reference to "horizons" to eliminate confusion<br>**3.**) We have removed the references to the explicit time frames.<br>4.) The SDT attempted to provide clarity on the meaning of "counterflow" in R4 by requiring the use of specific formulas. | |
| Constellation Energy Commodities | What determines which ATC calculation method a transmission service provider adapts or the frequency they can change?<br>In R4 please add Transmission Customers to the notification list.<br>In R6 please add Transmission Customers to the list that the transmission service provider will make the information available.<br>Also, please better define "subject to security and confidentiality requirements." |
| **Response:** 1.) We believe the justification for and frequency of changes this is not a reliability issue, and should be handled elsewhere. R5 does require 14 days notice of any change.<br>2.) We believe that this should be handled through the NAESB process.<br>3.) We believe that this should be handled through the NAESB process.<br>4.) These are requirements that are specified in other standards and documents. | |
| Entergy | Notification as required in R4 is not necessary if the ATCID is to be posted on a public site. |
| **Response:** Public posting will be addressed by NAESB. The notification is strictly from a reliability perspective. | |
| ERCOT | See IRC comments submitted by Charles Yeung. |
| **Response:** See the responses to IRC's comments. | |
| FirstEnergy | R1 requires agreement on methodology among TSP, PCs and RCs and should include a method for handling disagreements.<br>R2 implies need for incorporating schedules but does not imply or explicitly state the incorporation of transmission |

<table>
<tr><th colspan="2">Question #9</th></tr>
<tr><th>Commenter</th><th>Comment</th></tr>
<tr><td></td><td>reservations.<br>R4.8 should require a written request as a means of formally documenting the request was made, received, and acknowledged.</td></tr>
<tr><td colspan="2">Response: The SDT agrees with these comments and has corrected these issues with the next draft.<br>1.) The standard has been modified such that a single entity is required to specify the methodology.<br>2.) The SDT has modified the requirement to remove any such implication from MOD-001; the appropriate individual methodologies address this requirement in more detail.<br>3.) We have eliminated the need to request the notifications.</td></tr>
<tr><td>HQT</td><td>For those entities that do not provide physical transmission service, some of the requirements in these standards do not apply. With the current arrangement of these proposed standards, the ATCID for these entities would clearly document what requirements of the standards are or are not applicable.</td></tr>
<tr><td colspan="2">Response: The SDT has attempted to clarify the entities to which the standard is applicable.  If there are specific requirements which you believe should not apply, please provide them in detail.</td></tr>
<tr><td>IESO</td><td>See IRC comments.</td></tr>
<tr><td colspan="2">Response: See the response to IRC's comments.</td></tr>
<tr><td>IRC</td><td>Please see our high level comments to the SAR which we feel need to be addressed first before providing any comments specific to this standard.</td></tr>
<tr><td colspan="2">Response: The drafting team responded to all comments submitted on the SAR.  These comments are publicly posted.</td></tr>
<tr><td>ITC</td><td>Given that three methods are acceptable for calculating AFC/ATC, MOD-001 is a necessary prelude to any methodology chosen.</td></tr>
<tr><td colspan="2">Response: Agree.</td></tr>
<tr><td>MEC</td><td>1.  I question the approach in R1 that calls for the Transmission Service Provider, Planning Coordinator, and the Reliablity Coordinator to agree to the appropriate ATC methodologies.  The Transmission Service Provider has the ultimate authority.  Also there are no provisions in the standard for a way to resolve disputes.  What happens if each of the three has a different idea as to which methodologies to use?  I believe that the Planning Coordinator and the Reliability Coordinator should be responsible for resolving disputes between Transmission Service Providers if there are issues with regard to flowgates that involve more than one Transmission Service Provider.  I suggest that either R1 be changed to have the Transmission Service Provider coordinate with the Planning Coordinator and the Reliability Coordinator the methodology or else, the words "as appropriate" be added to R1 so that, if necessary the functional entity that has the authority makes the decision when there is disagreement.<br>2.  In R6, "other party" who may request the information should be changed to "other Functional Entity" so as to more properly describe the parties who might have a reliability need for the information.<br>3.  The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and "reliable system operations" and others do not.  I recommend that the purpose in MOD-001-1 be revised to state:  "To promote the consistent and transparent application and documentation of Available Transfer Capability (ATC) calculations for reliable system operations."<br>4.  I note that the Standards Drafting Team has defined a scheduling horizon in addition to an operating horizon and</td></tr>
</table>

| Question #9 | |
|---|---|
| **Commenter** | **Comment** |
| | a planning horizon. I am not familiar with the use of a scheduling horizon and questions why the Standards Drafting Team established it and why they have defined it as provided in the standard. |
| **Response:** The SDT agrees with these comments and has corrected these issues with the next draft.<br>1.) We have changed this to be the responsibility of a single entity.<br>2.) We have eliminated the reference to other parties.<br>3.) We have changed the purposes to reflect the need for transparency.<br>4.) We eliminated the uses of the words horizons form the standard. | |
| MRO | 1. The MRO questions the approach in R1 that calls for the Transmission Service Provider, Planning Coordinator, and the Reliablity Coordinator to agree to the appropriate ATC methodologies. The Transmission Service Provider has the ultimate authority. Also there are no provisions in the standard for a way to resolve disputes. What happens if each of the three has a different idea as to which methodologies to use? The MRO believes that the Planning Coordinator and the Reliability Coordinator should be responsible for resolving disputes between Transmission Service Providers if there are issues with regard to flowgates that involve more than one Transmission Service Provider. MRO suggests that either R1 be changed to have the Transmission Service Provider coordinate with the Planning Coordinator and the Reliability Coordinator the methodology or else, the words "as appropriate" be added to R1 so that, if necessary the functional entity that has the authority makes the decision when there is disagreement.<br>2. In R6, "other party" who may request the information should be changed to "other Functional Entity" so as to more properly describe the parties who might have a reliability need for the information.<br>3. The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and "reliable system operations" and others do not. The MRO recommends that the purpose in MOD-001-1 be revised to state: "To promote the consistent and transparent application and documentation of Available Transfer Capability (ATC) calculations for reliable system operations."<br>4. The MRO notes that the Standards Drafting Team has defined a scheduling horizon in addition to an operating horizon and a planning horizon. The MRO is not familiar with the use of a scheduling horizon and questions why the Standards Drafting Team established it and why they have defined it as provided in the standard. |
| **Response:** The SDT agrees with these comments and has corrected these issues with the next draft.<br>1.) We have changed this to be the responsibility of a single entity.<br>2.) We have eliminated the reference to other parties.<br>3.) We have changed the purposes to reflect the need for transparency.<br>4.) We eliminated the uses of the words horizons form the standard. | |
| NPCC CP9 RSWG | For those entities that do not provide physical transmission service, some of the requirements in these standards do not apply. With the current arrangement of these proposed standards, the ATCID for these entities would clearly document what requirements of the standards are or are not applicable. |
| **Response:** The SDT has attempted to clarify the entities to which the standard is applicable. If there are specific requirements which you believe should not apply, please provide them in detail. | |
| SOCO Transmission | 1. As drafted, it is not completely clear as to which of the requirements would apply to long-term planning and which |

| Question #9 | |
|---|---|
| **Commenter** | **Comment** |
| | requirements would not apply. For example, R5 clearly limits the timeframe of the requirement to 13 months. However, R6 has no reference or indication of which timeframes this requirement would be applicable.<br>2. R6 requires that the data in R6.1 - R6.9 is shared with ". . . or other party with a demonstrated reliability need. . . ." To avoid potential conflicts with this data sharing, the term "reliability need" should be limited to those needs required to maintain reliability of the transmission system. |
| **Response:** 1) The SDT has modified the standard to limit the duration of data in R6 (R10 in the revised standard) to 13 months.<br>2) This issue has been addressed by removal of the "reliability-need" reference and listing the specific functional entities that are entitled to request the data. | |
| SRP | R2 - More clarification is required regarding exactly what period of time each of the time horizons represent. |
| **Response:** The SDT has removed the use of the word "Horizons" and explicitly indicated the timeframe. | |

**Maureen E. Long**
Standards Process Manager

May 25, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

## Announcement: Comment Period Opens

**The Standards Committee (SC) announces the following standards actions:**

### SAR and Draft Standards for Available Transfer Capability (Project 2006-07) Posted for 30-day Comment Period May 25–June 24, 2007

To fully address the directives in FERC Orders 890 and 693 relative to Available Transfer Capability (ATC), a "Supplemental ATC SAR" has been posted for a 30-day comment period. Please use the comment form to provide comments on this SAR.

The ATC Standard Drafting Team has posted a set of requirements distributed amongst six standards aimed at meeting the intent of the originally approved SARs for ATC/TTC/AFC and CBM/TRM as well as the directives in FERC Orders 890 and 693. The drafting team also posted a white paper that explains the following proposed organization of the revised set of standards:

- There is one "umbrella" standard with requirements related to ATC (MOD-001 and comment form)
- There are three separate standards to address the determination of ATC, with each also addressing associated requirements for TTC and ETC:
  - Network Response method of calculating ATC (MOD-028 and comment form)
  - Rated System Path method of calculating ATC (MOD-029 and comment form)
  - Flowgate Network Response method of calculating ATC (MOD-030 and comment form)
- There is a separate standard to address Capacity Benefit Margin (MOD-004 and comment form)
- There is a separate standard to address Transmission Reliability Margin (MOD-008 and comment form).

Because the modifications made to the standards are so extensive, no "redline" versions of the standards have been developed. The versions of the standards that have been posted contain only requirements — there are no measures or compliance elements. Once there is consensus on the requirements, the drafting team will add measures and compliance elements. Please use the comment forms posted with the proposed standards to provide comments on this set of standards.

## Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007

**Description of Current Draft:**

This is the second draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR with consideration of stakeholder comments and applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Respond to comments. | February 1, 2008 |
| 2. Post for 30-day pre-ballot review. | February 1, 2008 |
| 3. First ballot of standard. | March 3, 2008 |
| 4. Respond to comments. | April 10, 2008 |
| 5. Recirculation ballot. | April 10, 2008 |
| 6. 30-day posting before board adoption. | March 2, 2008 |
| 7. Board adoption. | April 24, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Flowgate:**

1.) A designated point on the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow on a Flowgate that will respect all System Operating Limits for that Flowgate.

**Available Flowgate Capability (AFC):** The flow capability remaining on a Flowgate for further commercial activity over and above already committed uses.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with a specific system facility removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on facility ratings. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Transmission Flowgate Capability to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs are used to determine Available Transmission Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** MOD-030-1

3. **Purpose:** To increase consistency and transparency in the development and documentation of transfer capability calculations for short-term Transmission services performed by entities using the Flowgate Methodology to support reliable system operations.

4. **Applicability:**

   **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for Posted Paths.

   **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate ATCs for Posted Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all six (MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, MOD-030-1)ATC-related standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service provider shall include in its “Available Transfer Capability Implementation Document” (ATCID) the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Identify Flowgates for used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Any Facility within the Transmission Operator’s area based on thermal, stability or voltage limits is a Flowgate.

**R2.1.2.** All first Contingency transfer analyses from all adjacent Balancing Authority source sink combinations such that at a minimum the first three limiting Elements/Contingency combinations within the Transmission Operator’s system are included as Flowgates.

2.1.2.1. Use Contingencies consistent with the Contingencies used in operations studies and planning studies for the applicable time periods.

**R2.1.3.** Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure OR any limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where

2.1.3.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF impact on the Flowgate.

**R2.2.** At a minimum, update the list of Flowgates to create, modify, or delete Flowgate definitions at least once per calendar quarter.

**R2.3.** Determine the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.4.** At a minimum, update the TFC once per calendar year.

**R2.5.** Provide the Transmission Service Provider with the updated TFCs within seven calendar days of their determination.

**R3.** The Transmission Operator shall use a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains Facility Ratings specified by the Transmission Owners and Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and topology for the Facilities within its Reliability Coordinator's Area.

**R3.5.** Contains modeling data and topology for at least three contiguous busses of the Bulk Electric System directly and synchronously connected to the tie-lines into the systems of each adjacent Reliability Coordinator Area.

**R3.6.** Contains modeling data and topology (or equivalent representation) for synchronous Facilities beyond three busses.

**R4.** When calculating AFCs, the Transmission Service Provider shall Use assumptions consistent with the assumptions used in operations studies and planning studies for the applicable time periods, including: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.1.** Contingencies.

**R4.2.** Modeling the impact of point-to-point reservations as follows:

- If the source has been specified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source has been specified in the reservation and the point can be mapped to an "equivalence" modeled in the Transmission Service Provider's Transmission model, use the modeled equivalence as the source.
- If the source has been specified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" modeled in the Transmission Service Provider's Transmission model, use the interface point with the adjacent upstream Transmission Service Provider as the source.
- If the source has not been specified, use the interface point with the adjacent upstream Transmission Service Provider as the source.
- If the sink has been specified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink has been specified in the reservation and the point can be mapped to an "equivalence" modeled in the Transmission Service Provider's Transmission model, use the modeled equivalence as the sink.
- If the sink has been specified in the reservation and the point can not be mapped to a discretely modeled point or an "equivalence" modeled in the Transmission Service Provider's Transmission model, use the interface point with the adjacent downstream Transmission Service Provider as the sink.
- If the sink has not been specified, use the interface point with the adjacent downstream Transmission Service Provider as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R5.1.** Include all expected generation and Transmission outages, additions, and retirements in effect during the period calculated for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.2.** For external (third-party) Flowgates, use any AFC for each specific Flowgate provided by that third party as the AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of Firm Network and Native Load Service, for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed, based on:

**R6.1.1.** For on-peak intra-day and next-day AFCs

6.1.1.1. Peak Load forecast for the on-peak period calculated, consistent with that used for planning and operations for applicable time periods, including native load and network service load

6.1.1.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run.

**R6.1.2.** For off-peak intra-day and next-day AFCs

6.1.2.1. Peak Load forecast for the off-peak period calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load

6.1.2.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run.

**R6.1.3.** For days two through 31AFCs

6.1.3.1.1 Peak Load forecast for the day calculated, consistent with that used for planning and operations for applicable time periods, including native load and network service load

6.1.3.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run.

**R6.1.4.** For months two through 13 AFCs

6.1.4.1. Peak Load forecast for the month calculated, consistent with that used for planning and operations for applicable time periods, including native load and network service load

6.1.4.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run.

**R6.2.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area not included in the model.

**R6.3.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts, not included in the model in excess of 3%[1] for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed. The impact of any Grandfathered firm contracts expected to be scheduled for the Transmission Service Provider's area not included in the model.

**R6.4.** The impact of any Grandfathered firm contracts expected to be scheduled not included in the model in excess of 3%[2] for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

[1] Transmission Service Providers may use a threshold lower than 3% if desired.

[2] Transmission Service Providers may use a threshold lower than 3% if desired.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service not included in the model for the Transmission Service Provider's area

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service not included in the model in excess of 3%[3] for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm contracts not included in the model for the Transmission Service Provider's area

**R7.4.** The impact of any Grandfathered non-firm contracts not included in the model in excess of 3%[4] for all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + Counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period,

**TFC** is the Total Flowgate Capability of the Flowgate,

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period,

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period,

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period,

**$Postbacks_{Fi}$** are adjustments to firm AFC due to postbacks for that period, as defined in Business Practices, and

**$Counterflows_{Fi}$** are adjustments to firm ATC as determined by the Transmission Service Provider and described in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + Counterflows$$

**Where:**

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[3] Transmission Service Providers may include impacts less than 3% if desired.

[4] Transmission Service Providers may include impacts less than 3% if desired.

**$ATC_{NF}$** is the non-firm Available Flowgate Capability for the Posted Path for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released for sale as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are adjustments to non-firm Available Flowgate Capability due to postbacks for that period, as defined in business practices.

**$Counterflows_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and described in their ATCID.

**R10.** The Transmission Service Provider shall convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$TC = \min\{PTC_1, PTC_2, \ldots PTC_n\} \text{ and } PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either ‘Available’ or ‘Total’).

**P** is the set of partial Transfer Capabilities (either available or total) for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or PTDF Flowgate.

**$PTC_n$** is the partial Transfer Capability (either ‘Available’ or ‘Total’) for a path relative to a Flowgate *n.*

**$FC_n$** is the Flowgate Capability (‘Available’ or ‘Total’) of a Flowgate *n*.

**$DF_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per quarter. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as data and models) that it determined the TFC for each Flowgate as defined in R2.3.(R2.3)

**M5.** The Transmission Operator shall provide evidence (such as logs) that it updated the TFCs for each Flowgate at least once per calendar year. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M8.** The Transmission Service Provider shall provide evidence (such as written documentation and studies) that the assumptions used in AFC calculation were consistent with those used in operations and planning studies for the same period. (R4.1)

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties were used instead of those calculated by the Transmission Operator. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ETC included the elements described in R6 and did not include any additional elements. (R6)

**M13.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ETC included the elements described in R7 and did not include any additional elements. (R7)

**M14.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm AFC used the algorithm and the elements described in R8 and did not include any additional elements. (R8)

**M15.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm AFC used the algorithm and the elements described in R9 and did not include any additional elements. (R9)

**M16.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Transfer Capabilities follows the procedure described in R10. (R10)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

**1.3. Data Retention**

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R6, R7, R8, R9, and R10 for the most recent calendar year plus current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Service Provider does not include in its ATCID the criteria for identifying Flowgates to be considered in AFC calculations. |
| R2. | The Transmission Operator has not updated its list of Flowgates for more than two consecutive quarters but not more than three consecutive quarters.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of Flowgates for more than three but not more than four consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their | The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of Flowgates for more than four but not more than five consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has | The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of Flowgates for more than five consecutive quarters.<br>**OR**<br>The Transmission Operator did not determine the TFC for a flowgate as described in R2.3.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | determination. | not been more than 28 days (four weeks) since their determination. | with its Flowgate TFCs in **more** than 28 days (4 weeks) of their determination. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Transmission Operator used Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and one of those Facility Ratings was used (or should have been used) to establish a TFC for one or more flowgates. | The Transmission Operator used Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and two to five of those Facility Ratings were used (or should have been used) to establish a TFC for one or more flowgates. | The Transmission Operator used Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and six to ten of those Facility Ratings were used (or should have been used) to establish a TFC for one more flowgates. | The Transmission Operator did not update the Transmission model per the schedule specified in R3.<br>**OR**<br>The Transmission Operator used Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and eleven or more of those Facility Ratings were used (or should have been used) to establish a TFC for one or more flowgates.<br>**OR**<br>The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>**OR**<br>The Transmission operator did not include in the Transmission model detailed modeling data and topology at least three contiguous busses of the BES for more than one adjacent Reliability Coordinator area. |
| R4. | N/A | N/A | N/A | The Transmission Service Provider did not use assumptions consistent with those used in operations and planning studies for the same period. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R5. | The Transmission Service Provider did not include one to ten expected generation or Transmission outages, additions or retirements in the AFC process. | The Transmission Service Provider did not include eleven to twenty-five expected generation and Transmission outages, additions or retirements in the AFC process. | The Transmission Service Provider did not include twenty-six to fifty expected generation and Transmission outages, additions or retirements in the AFC process. | The Transmission Service Provider did not use assumptions consistent with those used in operations and planning studies for the same period<br>**OR**<br>The Transmission Service Provider did not model reservations as described in R4.1.<br>**OR**<br>The Transmission Service Provider did not include more than fifty expected generation and Transmission outages, additions or retirements in the AFC process.<br>**OR**<br>The Transmission Service provider did not use AFC provided by a third party. |
| R6. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R6 when determining non-firm ETC, or used additional elements. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R7 when determining firm AFC, or used additional elements. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R8. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements. |
| R9. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R9. |
| R10. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R10. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
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**Description of Current Draft:**

This is the second draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR with consideration of stakeholder comments submitted in response to the first draft of the proposed standard and applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
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| 6. 30 Day posting before board adoption. | March 2, 2008 |
| 7. Board adopts MOD-001-1. | April 24, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Rated System Path Methodology:** The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC to derive Available Transmission Capability.

## A. Introduction

1. **Title:** **Rated System Path Methodology**
2. **Number:** MOD-029-1
3. **Purpose:** To increase consistency and transparency in the development and documentation of transfer capability calculations for Transmission services performed by entities using the Rated System Path Methodology to support reliable system operations.
4. **Applicability:**
   - **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for Posted Paths.
   - **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for Posted Paths.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all six (MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, MOD-030-1)ATC-related standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** When calculating TTCs for Posted Paths, the Transmission Operator shall use a Transmission model that meets the following criteria: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R1.1.** Includes at least:

**R1.1.1.** The Transmission Operator Area

**R1.1.2.** All Transmission Operator Areas contiguous with its own Transmission Operator Area

**R1.1.3.** Any other Transmission Operator Area linked to the Transmission Operator’s Area by joint operating agreement.

**R1.2.** Models all system elements as in-service for the assumed initial conditions.

**R1.3.** Models all generation Facilities larger than 20 MVA in the studied area.

**R1.4.** Models phase shifters in Non-regulating mode, unless otherwise specified in the ATCID.

**R1.5.** Uses current Facility Ratings as provided by the Transmission Owner and Generator Owner

**R1.6.** Uses peak load forecast by Balancing Authority.

**R1.7.** Uses Transmission Facility additions and retirements.

**R1.8.** Uses Generation Facility additions and retirements.

**R1.9.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon

**R1.10.** Models series compensation for each “Extra High Voltage (EHV)” line at the expected operating level unless specified otherwise in the ATCID.

**R1.11.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.12.** Where three phase fault damping is used to determine stability limits, identifies the percent used and includes justification for use unless specified otherwise in the ACTID.

**R2.** The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the maximum flow (reliability limit) that can be simulated on the Posted Path while at the same time satisfying all planning criteria for N-0, N-1, and N-2 contingencies as follows:

**R2.1.1.** When modeling normal conditions (N-0), do not model any Transmission Element above 100% of its continuous rating.

**R2.1.2.** When modeling N-1 or N-2 contingencies, the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its emergency rating.

**R2.1.3.** Do not exceed any Facility Ratings (including thermal and voltage ratings)

**R2.1.4.** Uncontrolled separation shall not occur.

**R2.1.5.** Initiate system disturbances for stability studies by a three-phase-to-ground fault on all modeled “Extra High Voltage (EHV)” buses adjacent to the major interconnection point of the modeled Posted Path.

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction.

**R2.3.** For a Posted Path whose capacity is limited by contract, set TTC on the Posted Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R1.2.1.

**R2.4.** For Posted Paths whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** Verify that the TTC for the Posted Path being studied does not adversely impact the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1

**R2.6.** Where multiple ownership of Transmission rights exists on a Posted Path, allocate TTC of that Posted Path in accordance with the contractual agreement made by the multiple owners of that Posted Path.

**R2.7.** For Posted Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and the Regional Entity has not taken action to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps undertaken, including the contingencies and assumptions used, when determining the TTC and the results of the study.

**R3.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the Posted Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that Posted Path.

**R4.** Each Transmission Operator shall establish the TTC at the lesser of the TTC calculated in MOD-029-1 or any System Operating Limit for that Posted Path. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for a Posted Path, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

$\mathbf{NL_F}$ is the firm capacity reserved to serve peak Native Load forecast commitments for the time period being calculated, to include Native Load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the capacity reserved for grandfathered Firm Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “Safe Harbor Tariff” accepted by FERC.

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service,

$\mathbf{ROR_F}$ is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

$\mathbf{OS_F}$ is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for a Posted Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

$\mathbf{NITS_{NF}}$ is the non-firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_{NF}}$ is the non-firm capacity reserved for grandfathered Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “Safe Harbor Tariff” accepted by FERC.

$\mathbf{PTP_{NF}}$ is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

$\mathbf{OS_{NF}}$ is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm.

**R7.** When calculating Firm ATC for a Posted Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + Counter\text{-}schedules_F$$

**Where**

**$ATC_F$** is the firm Available Transfer Capability for the Posted Path for that period.

**TTC** is the Total Transfer Capability of the Posted Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the Posted Path during that period.

**CBM** is the Capacity Benefit Margin for the Posted Path during that period.

**TRM** is the Transmission Reliability Margin for the Posted Path during that period.

**$Postbacks_F$** are adjustments to firm Available Transfer Capability due to postbacks for that period, as defined in business practices.

**$Counter\text{-}schedules_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and described in their Available Transfer Capability Implementation Document.

**R8.** When calculating non-firm ATC for a Posted Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC – ETC_F – ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + Counter\text{-}schedules_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the Posted Path for that period.

**TTC** is the Total Transfer Capability of the Posted Path for that period.

**$ETC_F$** is the sum of existing non-firm commitments for the Posted Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the Posted Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the Posted Path that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the Posted Path that has not been released for sale as non-firm capacity by the Transmission Service Provider during that period,

**$Postbacks_{NF}$** are adjustments to non-firm Available Transfer Capability due to postbacks for that period, as defined in business practices, and

**$Counter\text{-}schedules_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and described in its Available Transfer Capability Implementation Document.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce each Transmission model it used to calculate TTC for purposes of posting ATC for each Posted Path, as required in R1, for the time horizon(s) to be examined.

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC used in its posted ATC calculations, as required in R1.

**M1.2.** The Transmission model produced must show the use of each attribute specified in R1.1; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred.

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1 through R.12.

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (See R1.4, R.1.10, R1.11 and R1.12).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the source documents reflecting the values it used to meet the requirements in R.1.5 through R1.9 for the period examined. (R1)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the models, reports, or study results that it used to establish TTC in accordance with R2.1 through R2.7. (R2)

**M5.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R3)

**M7.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R.1.2 for each Posted Path, 2) Any corresponding SOLs for those Posted Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R6 and R7 for each Posted Path. (R4)

**M8.** Each Transmission Service Provider shall produce the algorithms it used to calculate ETCs for Firm and Non-Firm Transmission Service, as required in R5 and R6, showing that only the variables allowed in R5 and R6 were used to calculate ETCs.

**M8.1.** Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ETCs in R5 and R6.

**M9.** Each Transmission Service Provider shall produce the algorithms it used to calculate Firm and Non-Firm ATCs, as required in R7 and R8, showing that only the variables allowed in R7 and R8 were used to calculate ATCs.

**M9.1.** Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ATCs in R7 and R8.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

**1.3. Data Retention**

- The Transmission Operator shall have its latest models used to determine TTC and evidence of previous versions for R1. (M1 and M6)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain the latest version and the prior version of the source documents used to update its models to show compliance with R1. (M3)
- The Transmission Operator shall retain evidence to show compliance with R2.1 through R2.7 for the most recent three calendar years plus the current year. (M4)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M5)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R1, R3 and R4. (M6 and M7)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R5, R6, R7 and R8. (M8 and M9)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator met all but one of the modeling requirements specified in R1<br>**OR**<br>The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and one of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths. | The Transmission Operator met all but two of the modeling requirements specified in R1<br>**OR**<br>The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and two to five of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths. | The Transmission Operator met all but three of the modeling requirements specified in R1<br>**OR**<br>The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and six to ten of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths. | The Transmission Operator did not meet four or more of the modeling requirements specified in R1<br>**OR**<br>The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and eleven or more of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths. |
| R2 | N/A | N/A | N/A | The Transmission Operator did not calculate TTC using the process described in R2. |
| R3. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider after more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider after more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider after more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider 28 or more calendar days after the report was finalized. |
| R4. | N/A | N/A | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or the SOL for one to four Posted Paths. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in or the SOL, for five or more Posted Paths |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R5 when determining Firm ETC, or used additional elements. |
| R6. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R6 when determining Non-Firm ETC, or used additional elements. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R7 when determining Firm ATC, or used additional elements. |
| R8. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R8 when determining Non-Firm ATC, or used additional elements. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007

**Description of Current Draft:**

This is the second draft of the proposed standard posted for stakeholder comments.  This draft includes the modifications identified in the SAR with consideration stakeholder comments and applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Respond to comments. | February 1, 2008 |
| 2. Post for 30-day pre-ballot review. | February 1, 2008 |
| 3. First ballot of standard. | March 3, 2008 |
| 4. Respond to comments. | April 10, 2008 |
| 5. Recirculation ballot. | April 10, 2008 |
| 6. 30-day posting before board adoption. | March 2, 2008 |
| 7. Board adoption. | April 24, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC to derive Available Transfer Capability.

## A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and transparency in the development and documentation of transfer capability calculations for short-term Transmission services performed by entities using the Area Interchange Methodology to support reliable system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for Posted Paths.

   **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for Posted Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all six (MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, MOD-030-1) ATC-related standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining TTC: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations may be validated.

**R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

**R1.3.** Any contractual obligations for allocation of TTC.

**R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.

**R2.** When calculating TTC for Posted Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs (for intra-day and next-day ) for Posted Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's Area, all the following data as provided by adjacent Transmission Service Providers, and any of the following data provided by any other Transmission Service Providers with which coordination agreements have been executed, provided that data can be associated with Facilities that are explicitly represented in the Transmission model: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R3.1.** For on-peak intra-day TTCs, and next-day intra-peak TTCs, use (at a minimum):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements.

**R3.1.2.** Peak Load forecast for the on-peak period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For off-peak intra-day and next-day TTCs, use (at a minimum):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements.

**R3.2.2.** Peak Load forecast for the off-peak period being calculated.

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.** When calculating TTCs (for time periods beyond next day) for Posted Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's Area, all the following data as provided by adjacent Transmission Service Providers, and any of the following data provided by any other Transmission Service Providers with which coordination agreements have been executed, provided that data can be associated with Facilities that are explicitly represented in the Transmission model: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** For days two through 31 TTCs, use (at a minimum):

**R4.1.1.** Expected generation and Transmission outages, additions, and retirements.

**R4.1.2.** Peak Load forecast for the day being calculated.

**R4.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.2.** For months two through 13 TTCs, use (at a minimum):

**R4.2.1.** Expected generation and Transmission outages, additions, and retirements.

**R4.2.2.** Peak Load forecast for the month calculated.

**R4.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R5.** When calculating TTCs for Posted Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** Use all Contingencies meeting the criteria described in its ATCID.

**R5.2.** Respect any contractual allocations of TTC.

**R5.3.** Include, for each time period, the expected schedules using monthly or longer firm Transmission service, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for the Transmission Service Provider's Area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source has been specified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source has been specified in the reservation and the point can be mapped to an "equivalence" modeled in the Transmission Service Provider's Transmission model, use the modeled equivalence as the source.
- If the source has been specified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" modeled in the Transmission Service Provider's Transmission model, use the interface point with the adjacent upstream Transmission Service Provider as the source.
- If the source has not been specified, use the interface point with the adjacent upstream Transmission Service Provider as the source.
- If the sink has been specified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink has been specified in the reservation and the point can be mapped to an "equivalence" modeled in the Transmission Service Provider's Transmission model, use the modeled equivalence as the sink.

- If the sink has been specified in the reservation and the point can not be mapped to a discretely modeled point or an "equivalence" modeled in the Transmission Service Provider's Transmission model, use the interface point with the adjacent downstream Transmission Service Provider as the sink.
- If the sink has not been specified, use the interface point with the adjacent downstream Transmission Service Provider as the sink.

**R6.** Each Transmission Operator shall calculate TTC for each Posted Path as defined below, unless otherwise requested by the Transmission Service Provider: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** At least once per calendar week for TTCs used in hourly, and daily ATC calculations.

**R6.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R7.** Each Transmission Operator shall calculate TTC for each Posted Path using the following process: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

a. Determine the incremental Transfer Capability for each Posted Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:
   - A System Operating Limit is reached on the Transmission Service Provider's system, or
   - A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is greater than 5%.

b. If the limit in step 'a' can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

c. Sum the incremental Transfer Capability and all impacts of Firm Transmission Service that were included in the study model.

d. Use (as the TTC) the lesser of:
   - The sum of the incremental Transfer Capability and the impacts of Firm Transmission Service that were included in the study model, or
   - The sum of Facility Ratings of all ties comprising the Posted Path.

e. For Posted Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed that Transmission Operator's contractual rights.

**R8.** The Transmission Operator shall provide the Transmission Service Provider of that Posted Path with the most current value for TTC for that Posted Path within seven calendar days of its determination.

**R9.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for a Posted Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NITS_F$** is the firm capacity reserved for Network Integration Transmission Service reserved on Posted Paths that serve as interfaces with other Transmission Service Providers.

**$GF_F$** is the capacity reserved for Grandfathered Firm Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal

**$OS_F$** is the capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts on other Posted Paths as described in the ATCID.

**R10.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for a Posted Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity reserved for Network Integration Transmission Service reserved on Posted Paths that serve as interfaces with other Transmission Service Providers.

**$GF_{NF}$** is the capacity reserved for Grandfathered Non-Firm Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts on other Posted Paths as described in the ATCID.

**R11.** When calculating Firm ATC for a Posted Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + Counterflows_F$$

**Where:**

**$ATC_F$** is the firm Available Transfer Capability for the Posted Path for that period,

**TTC** is the Total Transfer Capability of the Posted Path for that period,

**$ETC_F$** is the sum of existing firm Transmission commitments for the Posted Path during that period,

**CBM** is the Capacity Benefit Margin for the Posted Path during that period,

**TRM** is the Transmission Reliability Margin for the Posted Path during that period,

**$Postbacks_F$** are adjustments to firm ATC due to postbacks for that period, as defined in Business Practices, and

**$Counterflows_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and described in their ATCID.

**R12.** When calculating Non-Firm ATC for a Posted Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the Posted Path for that period,

**TTC** is the Total Transfer Capability of the Posted Path for that period,

**$ETC_F$** is the sum of existing firm Transmission commitments for the Posted Path during that period,

**$ETC_{NF}$** is the sum of existing non-firm Transmission commitments for the Posted Path during that period,

**$CBM_S$** is the Capacity Benefit Margin for the Posted Path that has been scheduled on during that period,

**$TRM_U$** is the Transmission Reliability Margin for the Posted Path that has not been released for sale as non-firm capacity by the Transmission Service Provider during that period,

**$Postbacks_{NF}$** are adjustments to non-firm ATC due to postbacks for that period, as defined in Business Practices, and

**$Counterflows_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and described in their ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** The Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** The Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC.(R3) (R4)

**M4.** The Transmission Operator shall provide the contingencies used in determining TTC and its ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R5)

**M5.** The Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTCs to show that any contractual allocations of TTC were respected as required in R5.2. (R5)

**M6.** The Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that monthly or longer reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R5.3, and that estimated scheduled interchange was included in the determination of TTC. (R5)

**M7.** The Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to calculate TTCs at specific intervals) that TTCs have been calculated at least once per calendar week for TTCs used in hourly, and daily ATC calculations and at least once per calendar month for TTCs used in monthly ATC calculations per the specifications in R6.(R6)

**M8.** The Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R7. (R7)

**M9.** The Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that its provided its Transmission Service Provider with the most current values for TTC in accordance with R8.

**M10.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Firm ETC used the algorithm and elements described in R9 and did not include any additional elements. (R9)

**M11.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Non-Firm ETC used the algorithm and the elements described in R10 and did not include any additional elements. (R10)

**M12.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Firm ATC used the algorithm and the elements described in R11 and does not include any additional elements. (R11)

**M13.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Non-Firm ATC used the algorithm and the elements described in R12 and does not include any additional elements. (R12)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 and R4 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R5, R6, R7 and R8 for the most recent12 months.
- The Transmission Service Provider shall retain evidence to show compliance with R9, R10, R11 and R12 for the most recent12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has an ATCID that meets the intent of Requirement 1 but the ATCID is missing some minor information. | The Transmission Service Provider has an ATCID but it is missing one of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing two of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing three or more of the four required elements in R1. |
| R2. | The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and one of those Facility Ratings was used (or should have been used) to establish TTC for one or more Posted Paths. | The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and two to five of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths. | The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and six to ten of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths.<br>**OR**<br>The Transmission Operator did not include in the Transmission model modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator area. | The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and eleven or more of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths.<br>**OR**<br>The Transmission Operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>**OR**<br>The Transmission Operator did not include in the Transmission model detailed modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator areas. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Transmission Operator did not include one to ten expected generation and Transmission outages, additions or retirements in the TTC process. | The Transmission Operator did not include eleven to twenty-five expected generation and Transmission outages, additions or retirements in the TTC process. | The Transmission Operator did not include twenty-six to fifty expected generation and Transmission outages, additions or retirements in the TTC process. | In calculating TTCs for intra-day and next-day, the Transmission Operator did not include more than fifty expected generation and Transmission outages, additions or retirements in the TTC process.<br>**OR**<br>In calculating TTCs for intra-day and next-day, the Transmission Operator did not include the peak Load forecast or unit commitment in its TTC calculation as described in R3.1. |
| R4. | N/A | N/A | N/A | In calculating TTCs for time periods beyond next day, the Transmission Operator did not include more than fifty expected generation and Transmission outages, additions or retirements in the TTC process.<br>**OR**<br>In calculating TTCs for time periods beyond next-day, the Transmission Operator did not include the peak Load forecast or unit commitment in its TTC calculation as described in R4.1. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R5. | N/A | N/A | N/A | The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br>**OR**<br>The Transmission Operator did not respect contractual allocations of TTC.<br>**OR**<br>The Transmission Operator did not model reservations' sources or sinks as described in R5.3<br>**OR**<br>The Transmission Operator did not use monthly or longer reservations to estimate interchange or did not utilize that estimate in the TTC calculation as described in R5.3. |
| R6. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the minimum time frames specified in R6. |
| R7. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the minimum time frames specified in R7. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R8. | The Transmission Operator has not provided its Transmission Service Provider with its Posted Path TTCs within seven calendar days of their determination, but is has not been more than 14 calendar days since their determination. | The Transmission Operator has not provided its Transmission Service Provider with its Posted Path TTCs within calendar days of their determination, but is has not been more than 21 calendar days since their determination. | The Transmission Operator has not provided its Transmission Service Provider with its Posted Path TTCs within 21 calendar days of their determination, but is has not been more than 28 calendar days since their determination. | The Transmission Operator has not provided its Transmission Service Provider with its Posted Path TTCs within 28 or more calendar days of their determination |
| R9. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R9 when determining firm ETC, or used additional elements. |
| R10. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R10 when determining non-firm ETC, or used additional elements. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R11 when determining firm ATC, or used additional elements. |
| R12. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R12 when determining non-firm ATC, or used additional elements. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007

**Description of Current Draft:**

This is the second draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR with consideration of stakeholder comments from the first posting and applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Respond to comments. | February 1, 2008 |
| 2. Post for 30-day pre-ballot review. | February 1, 2008 |
| 3. First ballot of standard. | March 3, 2008 |
| 4. Respond to comments. | April 10, 2008 |
| 5. Recirculation ballot. | April 10, 2008 |
| 6. 30 Day posting before board adoption. | March 2, 2008 |
| 7. Board adopts MOD-001-1. | April 24, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Transmission Reliability Margin Implementation Document (TRMID**): A document that describes the implementation of a Transmission Reliability Margin methodology.

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**

2. **Number:** **MOD-008-1**

3. **Purpose:** To promote the consistent and transparent calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to ensure reliable system operations.

4. **Applicability:**

   **4.1.** Transmission Operator.

   **4.2.** Transmission Service Provider.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all six (MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, MOD-030-1)ATC-related standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** Identification of (on each of its respective Posted Paths or Flowgates) each of the following components of uncertainty if used in calculating TRM, and a description of how that component is used to calculate a TRM value:

- Aggregate Load forecast uncertainty (not included in determining generation reliability requirements).
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve sharing requirements.
- Inertial response and frequency bias.

**R1.2.** A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in the Transmission planning process for the corresponding time periods.

**R1.3.** The description of the method of TRM allocation across Posted Paths or Flowgates.

**R1.4.** The identification of the TRM calculation used for the following time periods:

**R1.4.1.** Same day and real-time.

**R1.4.2.** Day-ahead and pre-schedule.

**R1.4.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

**R1.5.** If TRM is zero for all the time periods listed in R1.4, a statement of that practice.

**R2.** The Transmission Operator shall only use the components of uncertainty from R1.1 to calculate TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.** Each Transmission Operator shall provide its TRMID, and any underlying documentation, work papers and load flow base cases used to determine TRM, to all of the following within seven calendar days of a request: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** The Transmission Service Provider responsible for tariff administration over the Facilities operated by the Transmission Operator

**R3.2.** The Reliability Coordinator responsible for oversight of the Facilities for which the Transmission Service Provider offers service.

**R3.3.** The Planning Coordinator responsible for oversight of the Facilities for which the Transmission Service Provider offers service.

**R4.** Each Transmission Service Provider shall make available (within seven calendar days of a documented request for such information) the TRMIDs used by its Transmission Operator(s), and any underlying documentation, work papers and load flow base cases used to determine TRM, to Transmission Service Providers who have made a request for such information. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** Each Transmission Operator shall calculate, at least once every 13 months (in accordance with the definitions in its TRMID), a TRM value for the following time periods (on each Posted Path or Flowgate) and shall provide these TRM values to its Transmission Service Provider(s) and Transmission Planner(s) within seven calendar days of the calculation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R5.1.** Same day and real-time.

**R5.2.** Day-ahead and pre-schedule.

**R5.3.** Beyond the day-ahead and pre-schedule, up to thirteen (13) months ahead.

## C. Measures

**M1.** The Transmission Operator shall provide its current TRMID that contains the information described in R1to show its compliance with R1. (R1)

**M2.** The Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, CBMID, and other evidence, (such as written documentation, study reports, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** The Transmission Operator shall provide a dated copy of any request for its TRMID or associated documentation, and evidence such as copies of emails or postal receipts that show the recipient, date and contents as evidence that the requested documentation was provided within the specified timeframe to the entities described in R3. (R3)

**M4.** The Transmission Service Provider shall provide a dated copy of any request for its Transmission Operator's TRMID or associated documentation, and evidence such as copies of emails or postal receipts that show the recipient, date and contents as evidence that the requested documentation was provided within the specified timeframe to the requesting entity as described in R4. (R4)

**M5.** The Transmission Operator shall provide evidence (such as logs and data that it determined TRM at least once every thirteen months for each of the listed time periods and provided it to their Transmission Service Provider(s) and Transmission Planner(s) as described in R5. (R5)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago. | The Transmission Operator has a TRMID that does not incorporate changes been made three or more months ago but less than six months ago. | The Transmission Operator has a TRMID that does not incorporate changes made six or more months ago but less than one year ago. | The Transmission Operator has a TRMID that does not incorporate changes that have been made more than one year ago.<br>**OR**<br>The Transmission Operator does not have a TRMID, or its TRMID does not include any of the information described in R1. |
| R2. | N/A | N/A | N/A | The Transmission Operator included elements of uncertainty not defined in R1 in their calculation of TRM or it included components of CBM in TRM. |
| R3. | The Transmission Operator did provide the TRMID to all entities specified in R3 but provided TRMID to all parties in more than 7 days but less than 14 days. . | The Transmission Operator did not provide the TRMID to one entities specified in R3<br>**OR**<br>provided TRMID to all parties in more than 14 days or more but less than 30 days. . | The Transmission Operator did not provide the TRMID to two entities specified in R3<br>**OR**<br>provided TRMID to all parties in more than 30 days or more but less than 60 days. | The Transmission Operator did not provide the TRMID to any of the entities specified in R3<br>**OR**<br>provided TRMID to all parties in more than 60 days. |

| | | | | |
|---|---|---|---|---|
| R4. | The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in more than 7 calendar days but no more than 14 days of a request by a Transmission Service Provider. | The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in more than 14 calendar days but no more than 30 days of a request by a Transmission Service Provider. | The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in more than 30 calendar days but no more than 60 days of a request by a Transmission Service Provider. | The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in 60 days or more of a request by a Transmission Service Provider Or did not make the current TRMID available. |
| R5. | The Transmission Operator did not provide the Transmission Planner with its determined TRM values. | The Transmission Operator did not determine TRM for any of the listed time frames within thirteen months of the previous determination, and the last determination was not more than 15 months ago. | The Transmission Operator did not determine TRM for any of the listed time frames within thirteen months of the previous determination, and the last determination was more than 15 months ago, but not more than 18 months ago.<br>**OR**<br>The Transmission Operator did not provide the Transmission Service Provider with its determined TRM values, and one or more of those values changed by more than twenty percent from the previous value given to the Transmission Service Provider. | The Transmission Operator did not determine TRM for any of the listed time frames within thirteen months of the previous determination, and the last determination was more than 18 months ago.<br>**OR**<br>The Transmission Operator has not provided the Transmission Service Provider with any determined TRM values. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

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**Generation Capability Import Requirement (GCIR):** The amount of generation capability from external sources requested by a Load-Serving Entity (LSE) (or group of LSEs with an aggregated need for Capacity Benefit Margin) to meet its generation reliability or reserve adequacy requirements as an alternative to internal resources.

**Capacity Benefit Margin Implementation Document (CBMID):** A document that describes the implementation of a Capacity Benefit Margin methodology.

## A. Introduction

1. **Title:** **Capacity Benefit Margin**

2. **Number:** **MOD-004-1**

3. **Purpose:** To promote the consistent and transparent calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support reliable system operations.

4. **Applicability:**

   **4.1. Functional Entity:**

   **4.1.1** Load-Serving Entity.

   **4.1.2** Transmission Service Provider.

   **4.1.3** Balancing Authority.

   **4.1.4** Transmission Planner.

5. **Facility Limitations/Specifications:**

   **5.1.** None.

6. **Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all six standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standards become effective on the first day of the first calendar quarter that is twelve months beyond the date the standards are approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service Provider shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** Its procedure for a Load-Serving Entity within a Balancing Authority associated with the Transmission Service Provider to request CBM to support its Generation Capability Import Requirement (GCIR).

**R1.2.** Its procedure and assumptions for setting CBM for each Posted Path or Flowgate based on Load-Serving Entity requests.

**R1.3.** Its procedure for a Load-Serving Entity to request the scheduling of energy over Transfer Capability set aside as CBM.

**R2.** The Transmission Service Provider shall make available the CBMID and any changes to the CBID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator within seven days of a change. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.** A Load-Serving Entity (or group of Load-Serving Entities with an aggregated need for CBM) that wants Transfer Capability to be set aside in the form of CBM shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Submit a request for CBM to the Transmission Service Provider and Transmission Planner identifying the amount of CBM requested for each month for each year for the next ten year period, that includes:

**R3.1.1.** The GCIR, specifying:

3.1.1.1. The Balancing Authority(ies) from which generation supporting the GCIR will be supplied or the specific Posted Paths to be utilized for import of the generation supporting the GCIR.

3.1.1.2. A monthly GCIR value for each month during the current year and following year for each Balancing Authority or Posted Path.

3.1.1.3. An annual GCIR value for each subsequent year for each Balancing Authority or Posted Path.

**R3.1.2.** Identification of all applicable reserve margin and resource adequacy requirements, and the entity(ies) responsible for establishing them, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities.

**R3.1.3.** A summary of the results of resource studies performed to determine the amount of the request, not to include confidential information.

**R3.1.4.** All resource studies (and supporting information) performed to determine the amount of the request.

**R3.2.** At least every thirty-one days, update the request provided per R3.1 to reflect any changes that alter future needs for CBM or indicate that no change is needed.

**R3.3.** Base the request provided per R3.1 on verifiable historical, state, regional transmission organization or regional entity criteria.

**R4.** Within fourteen calendar days of receiving a request or change to a request for CBM that meets the requirements defined in R3.1, the Transmission Service Provider shall set the CBM for the months requested as described in R3.1.1.2 as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.1.** Determine the amount of CBM (for use in R4.2) for each request by using one of the following::

**R4.1.1.** For the Area Interchange Methodology and the Rated System Path Methodology, using the requested Generation Capability Import Requirement for the Posted Path

**R4.1.2.** For the Flowgate Methodology, determining the significant impacts of each request on each Flowgate

4.1.2.1. Determine impacts of a request by multiplying the requested GCIR by the Distribution Factor for the transfer of that import from the specified Balancing Authority relative to the Flowgate.

4.1.2.2. Classify each impacts based on a Distribution Factor of 3% or greater as a significant impact.

**R4.2.** Set CBM for each Posted Path or Flowgate based on the sum of all requests such that all requests can be met simultaneously or all firm ATC or AFC has been allocated to CBM as follows:

**R4.2.1.** For Posted Paths, set the CBM for each Posted Path equal to the lesser of:

- The sum of all requests for GCIR for that Posted Path, minus the transfer capability set aside for reserve sharing for that Posted Path or
- The firm Available Transfer Capability (ATC) for that Posted Path

**R4.2.2.** For Flowgates, set the CBM for each Flowgate equal to the lesser of:

- The sum of the significant impacts of all requests for GCIR for that Flowgate minus the impact of transfer capability set aside for reserve sharing for that Flowgate, or
- The firm Available Flowgate Capability (AFC) for that Flowgate

**R4.3.** If the sum of all CBM requests can not be met simultaneously, and during the evaluation of monthly ATC or AFC, additional capacity becomes available, increase the CBM based on availability up to a maximum of the sum of all CBM requests.

**R5.** Within sixty calendar days of receiving a request or change to a request for CBM that meets the requirements defined in R3.1, the Transmission Planner shall set the CBM for the years requested as described in R3.1.1.3 as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** Use each GCIR to determine a margin to decrement Firm Transfer Capability for use in all future planning processes.

**R5.2.** Set the CBM for each Posted Path or Flowgate based on the sum of all CBM requests such that all requests can be met simultaneously or all available firm Transfer Capability has been allocated to CBM.

**R5.3.** If the sum of all requests can not be met simultaneously, and during the planning process, additional capacity becomes available, increase the CBM based on availability up to a maximum of the sum of all requests.

**R5.4.** Provide the Transmission Service Provider with the following:

**R5.4.1.** The total amount of CBM for each Posted Path or Flowgate on the Transmission Service Provider's system in each of the years specified in the original CBM request.

**R5.4.2.** If less than the sum of all requests was established as the CBM for any period, for each Posted Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the years specified in the original request.

**R6.** Within five days of the determination of CBM as described in R4 or R5, the Transmission Service Provider shall provide each Load-Serving Entity (or group of Load-Serving Entities with an aggregated need for CBM) that requested CBM and the Balancing Authority hosting its (their) load with a report that includes: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** The total amount of CBM for each Posted Path or Flowgate on the Transmission Service Provider's system in each of the months or years specified in the original request. If less than the sum of all requests was established as the CBM for any period:

- For each Posted Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the months and years specified in the original request
- The option to request a system impact study.

**R7.** The Transmission Service Provider and Transmission Planner shall each provide copies of the supporting data, including any models, used for allocating CBM over each Posted Path or Flowgate to the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R7.1.** Each of its associated Transmission Operators within seven calendar days of a modification to the CBM.

**R7.2.** To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, or Planning Coordinator within seven calendar days of their making a request for the data.

**R8.** The Load-Serving Entity that wants to schedule energy over Firm Transfer Capability set aside as CBM shall submit an Interchange Transaction Tag, and shall not request to schedule energy over Firm Transfer Capability set aside as CBM unless experiencing a NERC Energy Emergency Alert (EEA) 2 or higher. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R9.** When reviewing an Interchange Transaction Tag using CBM, the Balancing Authority and Transmission Service Provider shall waive any timing and ramping requirements. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R10.** The Transmission Service Provider shall approve any Interchange Transaction Tag using CBM that is submitted by an Energy Deficient Entity under an EEA2 if the CBM is available. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

## C. Measures

**M1.** Each Transmission Service Provider shall have its CBMID that includes the information specified in R1 as to show that it is compliant with R1. (R1)

**M2.** The Transmission Service Provider shall have evidence (such as logs and data, copies of electronic messages, or other equivalent evidence) to show that within seven days of a change to its CBMID, it made the CBMID available to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator. (R2)

**M3.** The Load-Serving Entity that wants CBM shall provide a copy of its CBM request with the supporting information specified in R3.1 to show that it is compliant with R3.1. (R3)

**M4.** The Load-Serving Entity that wants CBM shall provide dated copies of its updated CBM requests as evidence that it has updated its CBM request or confirmed no update was needed at least every thirty-one days, per R3.2 (R3).

**M5.** The Load-Serving Entity that wants CBM shall provide evidence (such as studies, historical data, copies of state or regional transmission organization reliability criteria, regional generation reliability criteria or other equivalent evidence) they it has based its CBM request on verifiable historical, state, regional transmission organization, or regional generation reliability criteria in accordance with R3.3. (R3)

**M6.** The Transmission Service Provider shall provide evidence including copies of requests for CBM and requests for changes to CBM and other evidence such as copies of the actual computations to set CBM, or other equivalent evidence to show that CBM for the months requested as described in R3.1.1.2 has been established using the process described in R4. (R4)

**M7.** The Transmission Planner shall provide evidence including copies of requests for CBM and requests for changes to CBM and other evidence such as copies of actual computations to set CBM, or other equivalent evidence to show that CBM for the years requested as described in R3.1.1.3 has been established using the process described in R5. (R5)

**M8.** The Transmission Planner shall provide evidence (such as written documentation of studies and supporting study models that model, in base loadflows, the GCIRs as identified in R3.1.1 by Load-Serving Entities) that demonstrates that the CBM has been used to determine a margin to decrement Firm Transfer Capability in planning processes as specified in R5.1. (R5)

**M9.** The Transmission Service Provider shall provide copies of the reports sent to Load-Serving Entities and Balancing Authorities along with other evidence (such as logs and data, copies of electronic messages, or other equivalent evidence) to show that within five days of the determination of CBM, a report meeting the requirements described in R6 was provided as specified. (R6).

**M10.** The Transmission Service Provider and Transmission Planner shall each provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in R7. (R7)

**M11.** The Load-Serving Entity that scheduled CBM shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time they requested a schedule using CBM, they were in an EEA2. (R8)

**M12.** Balancing Authorities and Transmission Service Providers shall provide evidence (such as operating logs and tag data) that they did not deny an Interchange Schedule using CBM based on the request not meeting timing or ramping requirements. (R9)

**M13.** The Transmission Service Provider shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any Interchange Transaction Tag using CBM for any energy deficient entity where the total CBM available was greater than the amount of CBM requested in the Tag. (R10)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority (CEA)

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7 and R10 for three calendar years.
- The Load-Serving Entity shall maintain evidence to show compliance with R3, and R8 for three calendar years.
- The Transmission Planner shall maintain evidence to show compliance with R5 and R7 for three calendar years.
- The Balancing Authority shall maintain evidence to show compliance with R9 for three calendar years.
- If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits

- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

**None.**

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made within the last three months. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago. | The Transmission Service Provider has CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago. | The Transmission Service Provider does not have a CBMID, or has a CBMID that does not incorporate changes that have been made more than twelve months ago. |
| R2. | The Transmission Service Provider makes available the CBMID and any changes to the CBID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator eight (8) or more days but not more than 14 days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator 14 or more days but not more than 21 days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator 21 or more days but not more than 28 days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator more than 28 days after a change was made. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Load Serving Entity did not update their request for CBM, or indicate that no update was needed, as described in R3.2. | The Load Serving Entity desiring CBM did not submit the information described in any one of the following: R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity did not update their request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 20MW or 10%, whichever is smaller, and not more than 30MW or 20%, whichever is smaller. | The Load Serving Entity desiring CBM did not submit the information described in any one of the following: R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity did not update their request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 20MW or 10%, whichever is smaller, and not more than 40MW or 30%, whichever is smaller. | The Load Serving Entity desiring CBM did not include one or more of the items specified in R3.1.1 in their request.<br>**OR**<br>The Load Serving Entity desiring CBM did not submit any of the information described in R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity did not update their request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 40MW or 30%, whichever is smaller.<br>**OR**<br>The Load Serving Entity requested GCIR greater than its needs for imports to meet reserve margin or resource adequacy requirements (not to include the incremental power flows from reserve sharing requirements), and the additional GCIR requested was more than 10MW in excess of the needed amount. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | N/A | N/A | The Transmission Service Provider set CBM for the months requested as described in R3.1.1.2 more than 14, but not more than 30, days after receiving a request for CBM.<br>**OR**<br>The Transmission Service Provider did not follow the process described in R4.1, R4.2, and R4.3. | The Transmission Service Provider set CBM for the months requested as described in R3.1.1.2 more than 30 days after receiving a request for CBM.<br>**OR**<br>The Transmission Service Provider did not follow the process described in R4.1, R4.2, and R4.3, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met. |
| R5. | N/A | N/A | The Transmission Planner set CBM for the years requested as described in R3.1.1.3 more than 60, but not more than 120, days after receiving a request for CBM.<br>**OR**<br>The Transmission Planner did not follow the process described in R5.1, R5.2, R5.3, and R5.4. | The Transmission Planner set CBM for the years requested as described in R3.1.1.3 more than 120 days after receiving a request for CBM.<br>**OR**<br>The Transmission Planner did not follow the process described in R5.1, R5.2, R5.3, and R5.4, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met. |
| R6. | The Transmission Service Provider provided the report to the requesting entities within 7 days (up to 2 days late) of determining the CBM | The Transmission Service Provider provided the report to the requesting entities within 12 days (up to 7 days late) of determining CBM | The Transmission Service Provider provided the report to the requesting entities within 19 days (up to 14 days late) of determining CBM | The Transmission Service Provider provided the report to the requesting entities within 20 or more days of determining CBM OR did not provide the report. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R7. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM in more than seven, but not more than fourteen, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM in more than fourteen, but not more than thirty, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM more than thirty, but not more than sixty, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM more than sixty days after the submission of the request. |
| R8. | N/A | N/A | N/A | A Load Serving Entity requested to schedule energy over CBM while not in an EEA2 |
| R9. | N/A | N/A | N/A | A Balancing Authority or Transmission Service Provider denied an Interchange Transaction Tag using CBM based on timing or ramping requirements. |
| R10. | N/A | N/A | N/A | The responsible entity has failed to demonstrate implementation or execution of the program/procedure requirement or directive |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC Authorized posting TTC/ATC/AFC SAR Development June 20 2005.
2. SAC Authorized the SAR to be development as a standard on February 14 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from February 15 – March 16, 2007.
5. SDT posted second draft for comment from May 25–June 25, 2007.

**Description of Current Draft:**

This is the third draft of the proposed standard posted for stakeholder comments. This draft represents consideration of stakeholder comments submitted with the second draft of the proposed revisions to MOD-001 as well as consideration of applicable FERC directives from FERC Order 693 and Order 890.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Respond to comments. | February 1, 2008 |
| 2. Post for 30-day pre-ballot review. | February 1, 2008 |
| 3. First ballot of standard. | March 3, 2008 |
| 4. Respond to comments. | April 10, 2008 |
| 5. Recirculation ballot. | April 10, 2008 |
| 6. 30-day posting before board adoption. | March 2, 2008 |
| 7. Board adoption. | April 24, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Posted Path:**

1) Any Balancing Authority to Balancing Authority interconnection;
2) Any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months;
3) Any path for which a Transmission Customer requests to have Available Transfer Capability or Total Transfer Capability posted.

**Available Transfer Capability Implementation Document (ATCID):** A document that describes the implementation of an Available Transfer Capability methodology.

**Transmission Operator Area:** The collection of Transmission assets over which the Transmission Operator is responsible for operating.

**Existing Transmission Commitments (ETC):** Committed uses of a Transmission Service Provider's Transmission system considered when determining Available Transfer Capability.

**Planning Coordinator:** See Planning Authority.

## A. Introduction

1. **Title:** Available Transfer Capability
2. **Number:** MOD-001-1
3. **Purpose:** To promote the consistent and transparent application and documentation of Available Transfer Capability (ATC) calculations for reliable system operations.
4. **Applicability:**
   - **4.1.** Transmission Service Provider.
   - **4.2.** Transmission Operator.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all six (MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, MOD-030-1)ATC-related standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall select one ATC methodology[1] (Area Interchange methodology, Rated System Path methodology, or Flowgate methodology) for each Posted Path per time period for use in determining Transfer Capabilities of those Facilities within its Planning Coordinator's planning area. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.** Each Transmission Service Provider shall calculate ATC values for the time periods listed below using the selected ATC methodology or methodologies: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

- **R2.1.** Hourly ATC values for at least the next 168 hours.
- **R2.2.** Daily ATC values for at least the next 31 days.
- **R2.3.** Monthly ATC values for at least the current month plus the next 12 months.

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- **R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC calculations may be validated.
- **R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows or counter-schedules.
- **R3.3.** The identity of the Planning Coordinator and Transmission Operator associated with each Facility under the Transmission Service Provider's tariff.

[1] All Posted Paths do not have to use the same ATC Methodology and no particular Posted Path must use the same ATC Methodology for all time periods.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer capability.

**R3.5.** The identity of the Transmission Service Providers from which it receives data for use in calculating transfer capability.

**R3.6.** Allocation methodologies.

**R4.** When determining the impact of counterflows in the determination of firm ATC or AFC, the Transmission Service Provider shall use 0% of calculated counterflows based on reservations and/or schedules unless otherwise specified within the Transmission Service Provider's ATCID. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R5.** When determining the impact of counterflows in the determination of non-firm ATC or Available Flowgate Capability (AFC), the Transmission Service Provider shall apply the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R5.1.** Use 0% of calculated counterflows based on reservations unless otherwise specified within the Transmission Service Provider's ATCID.

**R5.2.** Use 100% of calculated counterflows based on schedules unless otherwise specified within the Transmission Service Provider's ATCID.

**R6.** The Transmission Service Provider shall notify the following entities (via electronic mail) before implementing a new or revised ATCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

**R6.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

**R6.3.** Each Transmission Operator associated with the Transmission Service Provider's area.

**R6.4.** Each Planning Coordinator adjacent to the Transmission Service Provider's area.

**R6.5.** Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

**R6.6.** Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

**R7.** The Transmission Service Provider shall make available the ATCID and any changes to the ATCID to all of the entities specified in R6. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R8.** When calculating Total Transfer Capability (TTC), AFC and ATC, the Transmission Operator and Transmission Service Provider shall each use assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R9.** Each Transmission Service Provider shall update ATC at a minimum on the following frequency: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R9.1.** For hourly ATC, once per hour.

**R9.2.** For daily ATC, once per day.

**R9.3.** For monthly ATC, once a week.

**R10.** Within fourteen calendar days of a request of any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator, each Transmission Service Provider shall begin to make available on the schedule specified by the requester (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider), unless another request already specifies data on a more frequent basis, to each requester, current versions of the following data as requested in electronic format for use in ATC calculations, for up to 13 months into the future (subject to confidentiality and security requirements): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R10.1.** Expected generation and Transmission outages, additions, and retirements.

**R10.2.** Peak Load forecasts.

**R10.3.** Unit commitments and dispatch orders, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:

- Dispatch order
- Participation factors
- Block dispatch

**R10.4.** Firm and non-firm Network Integration Transmission Service details.

**R10.5.** Confirmed firm and non-firm Transmission reservations.

**R10.6.** Grandfathered firm and non-firm contracted transmission capacity on an aggregated basis.

**R10.7.** Firm roll-over rights.

**R10.8.** Any firm and non-firm adjustments to reflect parallel path impacts.

**R10.9.** Power flow models and underlying assumptions.

**R10.10.** Contingencies, provided in one or more of the following formats:

- A list of Elements
- A list of Flowgates
- A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider

**R10.11.** Facility Ratings.

**R10.12.** Counterflows.

**R10.13.** Values of ATC, ETC, Capacity Benefit Margin (CBM), Transmission Reliability Margin), and TTC for all Posted Paths.

**R10.14.** Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider when selling Transmission service.

**R10.15.** Source and sink identification and mapping to the model.

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one or more of the specified ATC methodologies for use in determining Transfer Capabilities of those

Facilities for each Posted Path per timeframe within the Planning Coordinator's planning area. (R1).

**M2.** The Transmission Service Provider shall provide ATC values and identification of the selected ATC methodologies along with other evidence (such as written documentation, processes, or data)to show it calculated ATC for the following using the selected methodology or methodologies chosen as part of R1 (R1):

- There has been at least 168 hours of hourly ATC values calculated at all times.
- There has been at least 31 days of daily ATC values calculated at all times.
- There has been at least 12 months plus the current month of monthly ATC values calculated at all times.

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** The Transmission Service Provider shall provide its ATCID and other evidence (such as documentation and data) to show that it determined counterflows based on the rules in R4 and R5. (R4) (R5)

**M5.** The Transmission Service Provider shall provide copies of its dated electronic mail messages used to make notifications in accordance with R6 as evidence that it has notified the entities specified in R5 before a new or revised ATCID was implemented (R6)

**M6.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R6, as required by R7. (R7)

**M7.** The Transmission Service Provider and Transmission Operator shall each provide a copy of the assumptions used to calculate TTC, ATC and AFC as well as copies of operations and planning studies and other evidence (such as written documentation, models, studies, supporting information, or data) to show that the assumptions used in determining TTC, ATC, and AFC were consistent with those used in operations or planning studies for the time period studied. (R8)

**M8.** The Transmission Service Provider shall provide evidence (such as logs or data) that it has updated the hourly, daily, and monthly ATC on at least the minimum frequencies specified in R9.

**M9.** The Transmission Service Provider shall provide a copy of the dated request for ATC data as well as evidence to show the its response to that request (such as logs or data,) to show that within fourteen calendar days of receiving a request, the requested data items specified in R10 were made available in accordance with R10.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R5 and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- The Transmission Service Provider shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain evidence to show compliance with R7 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain evidence to show compliance with R9 and R10 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Operator did not select one or more of the specified methodologies. |
| R2. | N/A | N/A | N/A | The Transmission Operator or Transmission Provider did not calculate ATCs based on the time periods in R2.<br>**OR**<br>did not use the selected methodology(ies) to calculate ATC. |
| R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>**OR**<br>The Transmission Service Provider has an ATCID, but it does not include two or more of the information items described in R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>**OR**<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include any of the information described in R3. |
| R4. | N/A | N/A | N/A | The Transmission Service provider did not use counterflows in the determination of ATC as described in R4 or its ATCID. |
| R5. | N/A | N/A | N/A | The Transmission Service provider did not use counterflows in the determination of ATC as described in R5 or its ATCID. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R6. | The Transmission Service Provider did not notify one or more of the parties specified in R6 of a new or modified ATCID within 14 days of its effectiveness. | The Transmission Service Provider did not notify one or more of the parties specified in R6 of a new or modified ATCID within 30 days of its effectiveness. | The Transmission Service Provider did not notify one or more of the parties specified in R6 of a new or modified ATCID within 60 days of its effectiveness. | The Transmission Service Provider did not notify one or more of the parties specified in R6 of a new or modified ATCID within 90 days of its effectiveness. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in R7 |
| R8. | N/A | N/A | N/A | The Transmission Service Provider or Transmission Operator did not determine ATC using assumptions consistent with those used in planning and operations studies for the studied time period. |
| R9. | For Hourly, not calculated within 5hrs<br>**OR**<br>for Daily not calculated in 2 days,<br>**OR**<br>for Monthly- not calculated in 8 or more days, but less than 14 days | For Hourly, not calculated in more than 5 hours but not more than 10 hours,<br>**OR**<br>for Daily not calculated in 3 days,<br>**OR**<br>for Monthly- not calculated in 14 or more days, but less than 21 days | For Hourly, not calculated in10 hours or more, but not more than 15 hours,<br>**OR**<br>for Daily not calculated in 4 days,<br>**OR**<br>for Monthly- not calculated in 21 or more days, but less than 28 days | For Hourly, not calculated in15 hours or more,<br>**OR**<br>for Daily not calculated in 5 days or more,<br>**OR**<br>for Monthly- not calculated in 28 or more days. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R10 | N/A | The Transmission Service Provider took more than 14 calendar days but less than 28 calendar days from receiving a request, to make available the requested data items specified in R10 to the entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R10. | The Transmission Service Provider took 28 or more calendar days, but less than 60 calendar days from receiving a request, to make available the requested data items specified in R10 to the entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R10. | The Transmission Service Provider took 60 calendar days or more from receiving a request, to make available the requested data items specified in R10 to the entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R10. |

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared several standards related to the process of determining Available Transfer Capability (ATC). These standards are as follows:

- MOD-001-1 — Available Transfer Capability, which requires the selection of an ATC methodology and describes the parts of the ATC process that apply to all entities, regardless of methodology chosen.
- MOD-004-1 — Capacity Benefit Margin, which describes the reliability aspects of determining and maintaining a Capacity Benefit Margin and the conditions under which that margin may be used.
- MOD-008-1 — Transmission Reliability Margin Calculation Methodology, which describes the reliability aspects of determining and maintaining a Transmission Reliability Margin and what components of uncertainty may be considered when making that determination.
- MOD-028-1 — Area Interchange Methodology, which describes the Area Interchange methodology (previously referred to as the Network Response ATC methodology) for determining ATC.
- MOD-029-1 — Rated System Path Methodology, which describes the Rated System Path methodology for determining ATC.
- MOD-030-1 — Flowgate Methodology, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining ATC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this set of standards can be implemented.

## Modified Standards

FAC-012 ,FAC-013, MOD-002, MOD-003, MOD-005, MOD-006, MOD-007, and MOD-009 should be retired when these standards become effective. These elements are either redundant, being addressed in the other standards, or are being handled by NAESB.

## Compliance with Standards

Once this set of standards becomes effective, the responsible entities identified in the applicability section of each standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-001 | ■ | | ■ | | | |
| MOD-004 | | ■ | ■ | ■ | | ■ |

| | | | | | | |
|---|---|---|---|---|---|---|
| MOD-008 | ■ | ■ | ■ | ■ | ■ | ■ |
| MOD-028 | ■ | | ■ | | | |
| MOD-029 | ■ | | ■ | | | |
| MOD-030 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standards should become effective on the first day of the first calendar quarter that is twelve months beyond the date that all six standards are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standards become effective on the first day of the first calendar quarter that is twelve months beyond the date the standards are approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standards (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Summary of Directives in FERC Orders 890 and 693 and Corresponding ATC-Related Standards and Requirements

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| ATC | 890 | 211 | Standard AFC->ATC Calculation | MOD-030 R9 | As TDU Systems note, there is neither a definition of AFC in NERC's Glossary nor an existing reliability standard that discusses the AFC method. In order to achieve consistency in each component of the ATC calculation (discussed below), we direct public utilities, working through NERC, to develop an AFC definition and requirements used to identify a particular set of transmission facilities as a flowgate. However, we remind transmission providers that our regulations require the posting of ATC values associated with a particular path, not AFC values associated with a flowgate. Transmission providers using an AFC methodology must therefore convert flowgate (AFC) values into path (ATC) values for OASIS posting. In order to have consistent posting of the ATC, TTC, CBM, and TRM values on OASIS, we direct public utilities, working through NERC, to develop in the MOD-001 standard a rule to convert AFC into ATC values to be used by transmission providers that currently use the flowgate methodology. |
| ATC | 890 | 212 | Firm ATC uses only Firm Commitments | MOD-028 R9, R11<br>MOD-029 R5, R7<br>MOD-030 R5, R7 | The Commission also believes that further clarification is necessary regarding the calculation algorithms for firm and non-firm ATC.  Currently, NERC has no standards for calculating non-firm ATC. We find that the same potential for discrimination exists for non-firm transmission service as for firm service and that greater uniformity in both firm and non-firm ATC calculations will substantially reduce the remaining potential for undue discrimination. Therefore, we direct public utilities, working through NERC, to modify related ATC standards by implementing the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows. We understand that these principles are currently followed by most transmission providers and believe they should be clearly set forth in the ATC-related reliability standards. As described below, each transmission provider's Attachment C must include a detailed formula for both firm and non-firm ATC, consistent with the modified ATC-related reliability standards. |
| ATC | 890 | 212 | Non-Firm ATC uses firm and non-firm commitments, postbacks or redirected services, unscheduled service, and counterflows | MOD-028 R10, R12<br>MOD-029 R6, R8<br>MOD-030 R6, R8<br><br>Unscheduled service will be handled as a postback under the NAESB Business Practices. | |
| ATC | 890 | 237 | Develop consistent practices for calculating TTC/TFC | MOD-028 R1, R2, R3, R4, R5<br>MOD-029 R1<br>MOD-030 R2.3, R2.4, R9 | The Commission adopts the NOPR proposal and directs public utilities, working through NERC, to develop consistent practices for calculating TTC/TFC. We direct public utilities, working through NERC, to address, through the reliability standards process, any differences in developing TTC/TFC for transmission provided under the pro forma OATT and for transfer capability for native load and reliability assessment studies. |
| ATC | 890 | 237 | Address differences between Pro-Forma TTC and Native Load/Reliability Assessment TTC | MOD-001 R8<br>MOD-028 R1, R2, R3, R4, R5<br>MOD-029 R1<br>MOD-030 R2.3, R2.4, R9 | |

## Summary of Directives in FERC Orders 890 and 693 and Corresponding ATC-Related Standards and Requirements

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| ATC | 890 | 243 | Standard calc of native load use - include in MOD-001 | MOD-028 R3, R6, R7<br>MOD-029 R5<br>MOD-030 R6.1<br><br>Note this is not contained in MOD-001, as the methodologies each implement this differently for logistical reasons. | To achieve greater consistency in ETC calculations and further reduce the potential for undue discrimination, the Commission adopts the NOPR proposal and directs public utilities, working through NERC and NAESB, to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses. We expect that NERC will address ETC through the MOD-001 reliability standard rather than through a separate reliability standard. By using MOD-001, the ETC calculation can be adjusted to be applicable to each of the three ATC methodologies under development by NERC. |
| ATC | 890 | 244 | In the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC. | Unscheduled service will be handled as a postback under the NAESB Business Practices. | In order to provide specific direction to public utilities and NERC, we determine that ETC should be defined to include committed uses of the transmission system, including (1) native load commitments (including network service), (2) grandfathered transmission rights, (3) appropriate point-to-point reservations, (4) rollover rights associated with long-term firm service, and (5) other uses identified through the NERC process. ETC should not be used to set aside transfer capability for any type of planning or contingency reserve, which are to be addressed through CBM and TRM. In addition, in the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC. |
| ATC | 890 | 244 | ETC = Native load (including Network) | MOD-028 R11<br>MOD-029 R5<br>MOD-030 R8 | |
| ATC | 890 | 244 | ETC = Grandfathered | MOD-028 R11<br>MOD-029 R5<br>MOD-030 R8 | |
| ATC | 890 | 244 | ETC = Appropriate PTP | MOD-028 R11<br>MOD-029 R5<br>MOD-030 R8 | |
| ATC | 890 | 244 | ETC = Long-term Rollover rights | MOD-028 R11<br>MOD-029 R5<br>MOD-030 R8 | |
| ATC | 890 | 244 | Define any additional ETC components | MOD-028 R11<br>MOD-029 R5<br>MOD-030 R8 | |

## Summary of Directives in FERC Orders 890 and 693 and Corresponding ATC-Related Standards and Requirements

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| ATC | 890 | 245 | Reservations with Same POR whose SUM would exceed gen nameplate must be addressed | Not Addressed. The team does not believe this can be addressed any different that currently handled without compromising reliability. The customer has the right to schedule, and that right must be planned for. | We agree with TDU Systems that inclusion of all requests for transmission service in ETC would likely overstate usage of the system and understate ATC. We therefore find that reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at POR. This will prevent overly unrealistic utilization of transmission capacity associated with power output from a generator identified as a POR. We direct public utilities, working through NERC, to develop requirements in MOD-001 that lay out clear instructions on how these reservations should be accounted. One approach that could be used is examining historical patterns of actual reservation use during a particular season, month, or time of day. |
| ATC | 890 | 262 | CBM =0 in Non-Firm Calc | MOD-028 R11<br>MOD-029 R5<br>MOD-030 R8 | Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage. |
| ATC | 890 | 273 | TRM <> 0 in Non-Firm Calc | MOD-028 R11<br>MOD-029 R5<br>MOD-030 R8 | The Commission also adopts the NOPR proposal to establish standards specifying the appropriate uses of TRM to guide NERC and NAESB in the drafting process. Transmission providers may set aside TRM for (1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, (6) automatic sharing of reserves, and (7) other uncertainties as identified through the NERC reliability standards development process. Because load, facility loading and other uncertainties constantly deviate, we will not require that TRM set aside capacity be set at zero in the non-firm ATC calculation. In other words, we will not require transfer capability that is set aside as TRM to be sold on a non-firm basis. We find that clear specification in this Final Rule of the permitted purposes for which entities may reserve CBM and TRM will virtually eliminate double-counting of TRM and CBM. |
| ATC | 890 | 292 | Planning Assumptions and ATC Assumptions should be the same | MOD-001 R8 | The Commission also adopts the NOPR proposal to require transmission providers to use data and modeling assumptions for the short- and long-term ATC calculations that are consistent with that used for the planning of operations and system expansion, respectively, to the maximum extent practicable. This includes, for example: (1) load levels, (2) generation dispatch, (3) transmission and generation facilities maintenance schedules, (4) contingency outages, (5) topology, (6) transmission reservations, (7) assumptions regarding transmission and generation facilities additions and retirements, and (8) counterflows. We find that requiring consistency in the data and modeling assumptions used for ATC |
| ATC | 890 | 292 | Load levels the same plan/ops vs. ATC | MOD-001 R8 | |
| ATC | 890 | 292 | Gen Dispatch the same plan/ops vs. ATC | MOD-001 R8 | |

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| ATC | 890 | 292 | TX and Gen Facilities maintenance the same plan/ops vs. ATC | MOD-001 R8 | calculations will remedy the potential for undue discrimination by eliminating discretion and ensuring comparability in the manner in which a transmission provider operates and plans its system to serve native load and the manner in which it calculates ATC for service to third parties. The Commission directs public utilities, working through NERC, to modify ATC standards to achieve this consistency. |
| ATC | 890 | 292 | Contingency outages the same plan/ops vs. ATC | MOD-001 R8 | |
| ATC | 890 | 292 | Topology the same plan/ops vs. ATC | MOD-001 R8 | |
| ATC | 890 | 292 | TX Reservations the same plan/ops vs. ATC | MOD-001 R8 | |
| ATC | 890 | 292 | Assumptions re: additions and retirements the same plan/ops vs. ATC | MOD-001 R8 | |
| ATC | 890 | 292 | Counterflows the same plan/ops vs. ATC | MOD-001 R8 | |
| ATC | 890 | 293 | Develop an approach for accounting for counterflows, in the relevant ATC standards and business practices. | MOD-001 R4, R5 | With regard to EPSA's request for the standardization of additional data inputs, we believe they are already captured in the Commission's proposal as adopted in this Final Rule. Xcel asks the Commission to require consistency in the determination of counterflows in the calculation of ATC. Counterflows are included in the list of assumptions that public utilities, working through NERC, are required to make consistent. We believe that counterflows, if treated inconsistently, can adversely affect reliability and competition, depending on how they are accounted for. Accordingly, we reiterate that public utilities, working through NERC and NAESB, are directed to develop an approach for accounting for counterflows, in the relevant ATC standards and business practices. We find unnecessary Xcel's request that we require a date certain for specific issues in the Western Interconnection to be addressed. Above we require public utilities, working through NERC, to modify the ATC standards within 270 days after the publication of the Final Rule in the Federal Register. |
| ATC | 890 | 295 | Load level modeling methodology the same | MOD-001 R8, R10<br>MOD-028 R3, R4<br>MOD-029 R5<br>MOD-030 R5.1 | We offer the following clarifications. In response to Southern, we clarify that we require consistent use of assumptions underlying operational planning for short-term ATC and expansion planning for long-term ATC calculation. We also clarify that there must be a consistent basis or approach to determining load levels. For example, one approach may be for transmission providers to calculate load levels using an on- and offpeak model for each month when evaluating yearly service requests and calculating yearly ATC. The same (peak- and off-peak) or alternative approaches may be used for monthly, weekly, daily and hourly ATC calculations. Regardless of the ultimate choice of approach, it is imperative that all transmission providers use the same approach to modeling load levels to enable the meaningful exchange of data among transmission providers. Accordingly, we direct public utilities, working through NERC, to develop consistent requirements for modeling load levels in MOD-001 for the services offered under the pro forma OATT. |

## Summary of Directives in FERC Orders 890 and 693 and Corresponding ATC-Related Standards and Requirements

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| ATC | 890 | 296 | Dispatch should include all DNRs and committed resources as expected to run, and uncommitted resources deliverable within CA, economically dispatched to meet balancing needs | MOD-001 R10<br>MOD-028 R3, R4<br>MOD-029 Not Applicable<br>MOD-030 R6.1 | With respect to modeling of generation dispatch, we direct public utilities, working through NERC, to develop requirements in NERC's MOD-001 reliability standard specifying how transmission providers shall determine which generators should be modeled in service, including guidance on how independent generation should be considered. We agree with Ameren that any modeling of base generation dispatch must model generators, including merchant generators, as they are expected to run. Accordingly, we direct public utilities, working through NERC, to revise reliability standard MOD-001 by specifying that base generation dispatch will model (1) all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run and (2) uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements. |
| ATC | 890 | 297 | How to model POR to POD without source/sink | MOD-028 R5<br>MOD-029 Not Applicable<br>MOD-030 R4.2 | Regarding transmission reservations modeling, we direct public utilities, working through NERC, to develop requirements in reliability standard MOD-001 that specify (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations. |
| ATC | 890 | 297 | How to model existing reservations | MOD-028 R5.3<br>MOD-029 Not Applicable<br>MOD-030 R4.2 | |
| ATC | 890 | 301 | ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, | MOD-001 R2, R9 | The Commission adopts the NOPR proposal and requires the development of reliability standards that ensure ATC is calculated at consistent intervals among transmission providers. The Commission thus directs public utilities, working through NERC and NAESB, to revise reliability standard MOD-001 to require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, e.g., generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities. ATC-related requirements for OASIS posting are discussed below. |
| ATC | 890 | 310 | Mandatory Data Exchange for ATC | MOD-001 R10 | The Commission adopts the NOPR proposal and directs public utilities, working through NERC, to revise the related MOD reliability standards to require the exchange of data and coordination among transmission providers and, working through NAESB, to develop complementary business practices. The following data shall, at a minimum, be exchanged among transmission providers for the purposes of ATC modeling: (1) load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) existing transmission reservations, including counterflows; (6) ATC recalculation frequency and times; and (7) source/sink modeling identification. The Commission concludes that the exchange of such data is necessary to support the reforms requiring consistency in the determination of ATC adopted in this Final Rule. As explained above, transmission providers are required to coordinate the calculation of TTC/TFC and ATC/AFC with others and this requires a standard means of exchanging data. |
| ATC | 890 | 310 | DEX Load | MOD-001 R10 | |
| ATC | 890 | 310 | DEX TX Plan and Contingency outages | MOD-001 R10 | |
| ATC | 890 | 310 | DEX Gen Plan and Contingency outages | MOD-001 R10 | |
| ATC | 890 | 310 | DEX Base dispatch | MOD-001 R10 | |
| ATC | 890 | 310 | DEX existing reservations incl counterflows | MOD-001 R10 | |
| ATC | 890 | 310 | DEX ATC recalc frequencies and times | MOD-001 R10 | |

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| ATC | 890 | 310 | DEX Source sink modeling identification | MOD-001 R10 | |
| ATC | 890 | 389 | Unscheduled Reservation released on non-firm and posted on OASIS | Unscheduled service will be handled as a postback under the NAESB Business Practices. | We affirm our statement in the NOPR proposal acknowledging that transfer capability associated with transmission reservations that are not scheduled in real time is required to be made available as non-firm, and posted on OASIS. |
| ATC | 693 | 782 | Criteria used to calculate transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system. | MOD-001 R8 | Although we are not proposing to approve or remand this proposed Reliability Standard, the Commission believes that it can be improved. The Commission believes that the process used to determine transfer capabilities should be transparent to the stakeholders, and agrees with International Transmission and MidAmerican that the results of those calculations should not be available for public disclosure but only for qualified entities on a confidential basis. In addition, the process and criteria used to determine transfer capabilities must be consistent with the process and criteria used for other users of the Bulk-Power System. Simply stated, the criteria used to calculate transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system. The Commission directs the ERO to take this into account in its Reliability Standards development process, and to modify the Reliability Standard consistent with Order No. 890 in Docket No. RM05-25-000. |
| ATC | 693 | 1050 | TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. | Not addressed. The team believes that structuring TTC to be within each of the three methodologies is more appropriate. | We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings. |
| ATC | 693 | 1051 | Modify FAC-012-1 and any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the pro forma OATT | Not addressed. The team believes that structuring TTC to be within each of the three methodologies is more appropriate. | The Commission directs the ERO, through the Reliability Standards development process, to modify FAC-012-1 and any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the pro forma OATT, and requires that those processes be the same as those used in operation and planning for native load and reliability assessment studies. Changes to the process of calculating TTC are appropriate if implementation is coordinated with revisions to the other applicable operating or planning standards. We acknowledge that reliability regions have historically calculated transfer capability using different approaches, and we agree that regional differences should be respected. However, as already discussed above regarding ATC, TTC requirements will be determined in the ERO Reliability Standards development process, and any request for a regional difference from the Reliability Standards must take place through the ERO process. |
| ATC | 693 | 1057 | Develop non-fill-in-the-blank Standard | We have attempted to do this. | Accordingly, the Commission neither accepts nor remands MOD-001-0 until the ERO submits additional information. Although the Commission does not propose any action with |

# Summary of Directives in FERC Orders 890 and 693 and Corresponding ATC-Related Standards and Requirements

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| ATC | 693 | 1057 | Define information to be shared between TSPs for ATC calculations | MOD-001 R10 | regard to MOD-001-0, we address above a number of concerns regarding the Reliability Standard, consistent with those set forth in Order No. 890. We direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that: (1) provide a framework for ATC, TTC and ETC calculation, developing industry-wide consistency of all ATC components; (2) require disclosure of algorithms, for both firm and non-firm ATC and processes used in the ATC calculation; (3) identify a detailed list of information to be exchanged among transmission providers for the purposes of ATC modeling; (4) include a requirement that the assumptions used in ATC and AFC calculations should be consistent with those used for planning the expansion or operation of the Bulk-Power System to the maximum extent practicable; (5) include a requirement that ATC be updated by all transmission providers on a consistent time interval; (6) include a requirement that applicable entities make available assumptions and contingencies underlying ATC and TTC calculations; (7) address only ATC/AFC while TTC/TFC should be addressed under transfer capability standards such as FAC-012-1 and (8) identify the applicable entities in terms of users, owners and operators of the Bulk-Power System. |
| ATC | 693 | 1057 | Planning Assumptions and ATC Assumptions should be the same | MOD-001 R8 | |
| ATC | 693 | 1057 | ATC should be updated on a consistent schedule | MOD-001 R9 | |
| ATC | 693 | 1057 | ATC/TTC Assumptions and Contingencies must be made available | MOD-001 R3, R10 | |
| ATC | 693 | 1057 | Put TTC in FAC section | Not addressed. The team believes that structuring TTC to be within each of the three methodologies is more appropriate. | |
| ATC | 693 | 1057 | Identify applicable entities | We have done so. | |
| ATC | 693 | 1105 | CBM must be 0 in non-firm ATC | MOD-028 R12<br>MOD-029 R8<br>MOD-030 R8 | The Commission approves MOD-006-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to Reliability Standard MOD-006-0 through the Reliability Standards development process that: (1) includes a provision that will ensure that CBM and TRM are not used for the same purpose; (2) provides that CBM should be used for emergency generation deficiencies; (3) modifies Requirement R1.2 to define “generation deficiency” based on a specific energy emergency alert level; (4) includes a provision that CBM should have a zero value in the calculation of non-firm ATC and (5) expands the applicability section to include the entities that actually use CBM, such as LSEs. |
| CBM | 890 | 257 | Develop clear standards for how the CBM value shall be determined, allocated across transmission paths, and used. | MOD-004 R1, R3, R4, R9, R10 | The Commission therefore adopts a combination of the NOPR options one and two, and declines to adopt option three. First, we require public utilities, working through NERC and NAESB, to develop clear standards for how the CBM value shall be determined, allocated across transmission paths, and used. We understand that NERC has already begun the process of modifying several of the CBM-related reliability standards and that the drafting process is a joint project with NAESB. |
| CBM | 890 | 259 | CBM shall only used to allow LSE to meet its generation reliability criteria | MOD-004 R8 | To ensure CBM is used for its intended purpose, CBM shall only be used to allow an LSE to meet its generation reliability criteria. Consistent with Duke's statement, we clarify that each LSE within a transmission provider's control area has the right to request the transmission provider to set aside transfer capability as CBM for the LSE to meet its historical, state, RTO, or regional generation reliability criteria requirement such as reserve margin, loss of load probability (LOLP), the loss of largest units, etc. |

# Summary of Directives in FERC Orders 890 and 693 and Corresponding ATC-Related Standards and Requirements

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| CBM | 890 | 260 | Define flowgate/path allocation process for CBM | MOD-004 R4.1 | We direct public utilities, working through NERC, to develop clear requirements for allocating CBM over transmission paths and flowgates. While we do not mandate a particular methodology for allocating CBM to paths and flowgates, one approach could be based on the location of the outside resources or spot market hubs that an LSE has historically relied on during emergencies resulting from an energy deficiency. |
| CBM | 890 | 262 | CBM Must be used only for generation deficiencies | MOD-004 R8, R10 | Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage. |
| CBM | 890 | 354 | Commission requires transmission providers to make any transfer capability set aside for CBM but unused for such purpose available on a non-firm basis and to post this availability on OASIS. | MOD-028 R12<br>MOD-029 R8<br>MOD-030 R8 | The Commission adopts the CBM posting requirements proposed in the NOPR. In doing so, we amend our OASIS regulations to incorporate the directives established in the CBM Order. Accordingly, we require transmission providers to post (and update) the CBM amount for each path. In addition, the Commission requires transmission providers to make any transfer capability set aside for CBM but unused for such purpose available on a non-firm basis and to post this availability on OASIS. Furthermore, the Commission requires transmission providers to post (and update) the TRM values for the paths on which the transmission provider already posts ATC, TTC, and CBM. |
| CBM | 890 | 358 | yearly CBM studies | MOD-004 R3.1, R3.2, R4, R5 | The Commission incorporates into its regulations the requirement in the CBM Order for a transmission provider to periodically reevaluate its transfer capability setaside for CBM. With respect to TAPS' concerns over the effort involved in the reevaluation process, we will require CBM studies to be performed at least every year. This requirement is consistent with the CBM Order, in which the Commission stated that the level of ATC set aside for CBM should be reevaluated periodically to take into account more certain information (such as assumptions that may not have, in fact, materialized). While changes requiring a reevaluation of CBM are longer-term in nature (e.g., installation of a new generator or a long-term outage), quarterly may be too frequent, though two years may be too long and may prevent a portion of the CBM setaside from being released as ATC. Moreover, annual reevaluation is consistent with the current NERC standard being developed in MOD-005. The requirement to evaluate CBM at least every year also is consistent with the CBM Order in that the Commission directed transmission providers to periodically reevaluate their generation reliability needs so as to make known the need for CBM and to post on OASIS their practices in this regard. |

## Summary of Directives in FERC Orders 890 and 693 and Corresponding ATC-Related Standards and Requirements

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| CBM | 693 | 1081 | What to do if CBM exceeds ATC? | MOD-004 R4.2 | We agree with TAPS that there is a need for clearer requirements in the standard regarding to whom and how to submit a request for CBM set-aside, and what the transmission service provider should do if the sum of all CBM requirements exceeds the amount of available transfer capability. We direct the ERO to address the reliability aspects in the Reliability Standards development process and explore with NAESB whether business practices would be required. |
| CBM | 693 | 1082 | CBM set aside at verified request of LSE | MOD-004 R3, R4, R5 | Accordingly, the Commission neither accepts nor remands MOD-004-0 until the ERO submits additional information. In the interim, compliance with MOD-004-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD-004-0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those set forth in Order No. 890. Therefore, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process to: (1) clarify that CBM shall be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria; (2) develop requirements regarding transparency of the generation planning studies used to determine CBM value; (3) modify the current Requirements to make clear the process for how CBM is allocated across transmission paths or flowgates; (3) modify its standard in order to prevent setting aside CBM and TRM for the same purposes; (4) modify the standard by adding LSE as an applicable entity and (5) coordinate with NAESB business practice standards. |
| CBM | 693 | 1082 | Require disclosure of CBM studies | MOD-004 R3.1.2, R3.1.3, R3.1.4, R7 | |
| CBM | 693 | 1082 | Define flowgate/path allocation process for CBM | MOD-001 R4.1 | |
| CBM | 693 | 1082 | No double counting | MOD-008 R2 | |
| CBM | 693 | 1082 | Add LSE, BA as applicable entity where necessary | MOD-004 R3, R8, R9 | |
| CBM | 693 | 1105 | CBM Must be used only for generation deficiencies | MOD-004 R8 | The Commission approves MOD-006-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to Reliability Standard MOD-006-0 through the Reliability Standards development process that: (1) includes a provision that will ensure that CBM and TRM are not used for the same purpose; (2) provides that CBM should be used for emergency generation deficiencies; (3) modifies Requirement R1.2 to define "generation deficiency" based on a specific energy emergency alert level; (4) includes a provision that CBM should have a zero value in the calculation of non-firm ATC and (5) expands the applicability section to include the entities that actually use CBM, such as LSEs. |
| CBM | 693 | 1105 | Generation Deficiency must be stated as an EEA level | MOD-004 R8 | |
| TRM | 890 | 273 | Explicit definition of what goes into TRM | MOD-008 R1 | The Commission also adopts the NOPR proposal to establish standards specifying the appropriate uses of TRM to guide NERC and NAESB in the drafting process. Transmission providers may set aside TRM for (1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, (6) automatic sharing of reserves, and (7) other uncertainties as identified through the NERC reliability standards development process. Because load, facility loading and other uncertainties constantly deviate, we will not require that TRM set aside capacity be set at zero in the non-firm ATC calculation. In other words, we will not require transfer capability that is set aside as TRM to be sold on a non-firm basis. We find that clear specification in this Final Rule of the permitted purposes for which entities may reserve CBM and TRM will virtually eliminate double-counting of TRM and CBM. |
| TRM | 890 | 273 | TRM = Load Forecast and Load Distribution Error | MOD-008 R1 | |
| TRM | 890 | 273 | TRM = Variation in facility loading | MOD-008 R1 | |
| TRM | 890 | 273 | TRM = uncertainty in tx topology | MOD-008 R1 | |
| TRM | 890 | 273 | TRM = loop flow | MOD-008 R1 | |
| TRM | 890 | 273 | TRM = variations in dispatch | MOD-008 R1 | |

## Summary of Directives in FERC Orders 890 and 693 and Corresponding ATC-Related Standards and Requirements

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| TRM | 890 | 273 | TRM = ARS | MOD-008 R1 | |
| TRM | 890 | 273 | Define any additional uses | MOD-008 R1 | |
| TRM | 890 | 273 | No double counting | MOD-008 R2 | |
| TRM | 890 | 275 | Max TRM Calc | Not addressed. We have not been able to identify any maximum calculation that stands out as a leading example to be made into a standard. TRM is a risk management tool, and its calculation may be legitimately different for various systems, regions, and companies. | In addition, we direct public utilities, working through NERC, to establish an appropriate maximum TRM. One acceptable method may be to use a percentage of ratings reduction, i.e., model the system assuming all facility ratings are reduced by a specific percentage. This is a relatively simple method and, if adopted as the reliability standard's method, should not restrict a transmission provider from using a more sophisticated method that may allow for greater ATC without reducing overall reliability. |
| TRM | 693 | 1082 | No double counting | MOD-008 R2 | Accordingly, the Commission neither accepts nor remands MOD-004-0 until the ERO submits additional information. In the interim, compliance with MOD-004-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD-004-0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those set forth in Order No. 890. Therefore, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process to: (1) clarify that CBM shall be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria; (2) develop requirements regarding transparency of the generation planning studies used to determine CBM value; (3) modify the current Requirements to make clear the process for how CBM is allocated across transmission paths or flowgates; (3) modify its standard in order to prevent setting aside CBM and TRM for the same purposes; (4) modify the standard by adding LSE as an applicable entity and (5) coordinate with NAESB business practice standards. |
| TRM | 693 | 1122 | Define flowgate/path allocation process for TRM | MOD-008 R1.3 | Consistent with the NOPR proposal and Order No. 890, the Commission directs the ERO to modify standard MOD-008-0 to clarify how TRM should be calculated and allocated across paths or flowgates. We understand that the standards drafting process is underway as a joint project with NAESB. We agree with International Transmission, MidAmerican and MISO about the need for more uniformity and transparency in TRM calculation methodology and use, in order to eliminate potential reliability and discrimination concerns. Consistent with Order No. 890, the Commission directs the ERO to specify the parameters for entities to use in determining uncertainties for which TRM can be set aside and used, such as: (1) load forecast and load distribution error; (2) variations in facility loadings; (3) uncertainty in transmission system topology; (4) loop flow impact; (5) variations in generation dispatch; (6) automatic reserve sharing and (7) other uncertainties as identified through the NERC Reliability Standards development process. We find that clear specification in this Final Rule |
| TRM | 693 | 1122 | TRM = Load Forecast and Load Distribution Error | MOD-008 R1 | |
| TRM | 693 | 1122 | TRM = Variation in facility loading | MOD-008 R1 | |
| TRM | 693 | 1122 | TRM = uncertainty in transmission topology | MOD-008 R1 | |
| TRM | 693 | 1122 | TRM = loop flow | MOD-008 R1 | |

| Topic | Order | Cite | Brief Description | Addressed By | Detailed Citation |
|---|---|---|---|---|---|
| TRM | 693 | 1122 | TRM = variations in dispatch | MOD-008 R1 | of the permitted purposes for which entities may reserve CBM and TRM will also virtually eliminate double-counting of TRM and CBM. Therefore, we direct the ERO to determine clear requirements regarding permitted uses for TRM through its Reliability Standards development process. |
| TRM | 693 | 1122 | TRM = ARS | MOD-008 R1 | |
| TRM | 693 | 1122 | Define any additional uses | MOD-008 R1 | |
| TRM | 693 | 1126 | Explicit definition of what goes into TRM | MOD-008 R1 | The Commission neither accepts nor remands MOD-008-0 until the ERO submits additional information. In the interim, compliance with MOD-008-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD-008-0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those proposed in Order No. 890. Accordingly, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process including: (1) clear requirements on how TRM should be calculated, including a methodology for determining the maximum TRM value, and allocated across paths; (2) clear requirements for permitted purposes for which TRM can be set aside and used; (3) clear requirements for availability of documentation that supports TRM determination and (4) expanding the applicability to add planning authorities and reliability coordinators and any other appropriate entity identified in the Reliability Standards development process. |
| TRM | 693 | 1126 | Max TRM Calc | Not addressed. We have not been able to identify any maximum calculation that stands out as a leading example to be made into a standard. TRM is a risk management tool, and its calculation may be legitimately different for various systems, regions, and companies. | |
| TRM | 693 | 1126 | Standard on How TRM to be calculated | Not addressed. We have not been able to identify any single methodology that stands out as a leading example to be made into a standard. TRM is a risk management tool, and its calculation may be legitimately different for various systems, regions, and companies. | |
| TRM | 693 | 1126 | Add PC, RE to applicable entities | Not addressed. We do not find that these entities need to be added to the TRM standard. | |

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

**Maureen E. Long**
Standards Process Manager

October 31, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

## Announcement: Comment Period Opens

**The Standards Committee (SC) announces the following standards action:**

### Draft Standards for Available Transfer Capability (Project 2006-07) Posted for 45-day Comment Period October 31–December 14, 2007

The ATC Standard Drafting Team has posted a revised set of standards related to the determination of Available Transfer Capability (ATC) and an associated implementation plan for a 45-day comment period. This set of standards is aimed at ensuring the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). The standards have been revised based on stakeholder comments, coordination with NAESB, and the directives in the FERC Orders 693 and 890. The six standards posted for review include:

- MOD-001 — Available Transfer Capability — An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.
- MOD-004 — Capacity Benefit Margin — A standard that describes the requesting, calculation, and use of CBM.
- MOD-008 — Transmission Reliability Margin — A standard that describes the calculation and use of TRM.
- MOD-028 — Area Interchange Methodology (formerly called the Network Response ATC Methodology) — A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.
- MOD-029 — Rated System Path Methodology — A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection
- MOD-030 — Flowgate Methodology (formerly called the Network Response Flowgate Methodology) — A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC

Because the modifications made to the standards are so extensive, no “redline” versions of the standards have been developed. Many of the changes made to the standards added details to comply with the directives in FERC Orders 693 and 890. To assist in reviewing the standards, the drafting team has assembled a table that includes the relevant FERC directives and identifies the standard and requirement that addresses that directive. Please use the comment form to provide comments on this set of standards and the associated implementation plan.

**Standards Development Process**

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

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Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

### Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

# Arrangement of Requirements within the Proposed Set of 'ATC' Standards

## MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

## Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☐ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Kenneth A. Sugden | |
| Organization: | Flathead Electric Cooperative | |
| Telephone: | 406 751 4401 | |
| E-mail: | gmgr@fec.cc | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment** **(check all industry segments in which your company is registered)** |
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
| ☐ FRCC | ☐ | 2 — RTOs and ISOs |
| ☐ MRO | ☒ | 3 — Load-serving Entities |
| ☐ NPCC | ☐ | 4 — Transmission-dependent Utilities |
| ☐ RFC | ☐ | 5 — Electric Generators |
| ☐ SERC | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

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- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

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- Added measures and compliance elements.

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### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

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- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

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*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

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☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

2) In reference to MOD-030-1/R10, the requirement should be altered as follows: "The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC's for its network and provides a tool for AFC-to-ATC conversion (in BPA's case, Power Utilization Factor Calculators). We believe at this time that this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Bert Bressers |
| Organization: | Southwest Power Pool |
| Telephone: | 501-614-3300 |
| E-mail: | bbressers@spp.org |

| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment (check all industry segments in which your company is registered)** |
|---|---|---|
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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>
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>
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>
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>
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>
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The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

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- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

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☐ Yes

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Comments:

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Comments:

MOD-001-1

R1

1.Is it correct that R1 assumes that all the Transmission Operators within the Tariff footprint of a Transmission Providers shall agree upon the applicable ATC Methodology for the Tariff footprint and the TSP shall base the ATC Calculations and the ATCID document on the selected ATC methodology or methodologies. Meaning R1 and R2 are related.

2.Is it correct R1 assumes that a TSP can only have one methodology for the time frame specified in R2.1. Same for R2.2 and R2.3. They can be different for R2.1 and R2.2 or R2.3.

3.The MOD-001-1 responsibilities of Transmission Operator are not fully clear. Is MOD-001-1 assuming that a Transmission Operator can calculate ATC based on his selected ATC Methodology for his Operator Area independent from TSP for purpose of evaluating some of his internal Service Requests and that TSP can have a different Methodology for the Tariff footprint that includes Operator Area of TOP. Meaning no relation between R1 and R2, TOP and TSP can have different methodologies for ATC Calculations.

R8

1.Is MOD -001-1 assuming that somehow the Transmission Operator is calculating TTC, AFC or ATC or any other data that will be used for purpose of evaluating Service Requests.

2. What is the list of assumptions that are referred to in R8.

R10.13

1.If a TSP uses flow gate Methodology (MOD-030-1) what ETC need to be posted, the ETC on flow gate basis as specified in R7 MOD-030-1 or a ETC on path basis converted from ETC flow gate basis to ETC path basis using conversion specified in R9 MOD-030-1.

2.Is it a correct assumption that ATC, ETC and TTC posted for a path can be values from 3 different constraints, so the numbers itself don't add up. Is this in line with what FERC had in mind when requesting posting of TTC, ATC and ETC.

3.There are "rumors" that Scenario Analyzer is not considered being compliant by FERC with R10.3 standards . Are you aware of any additional NERC or NAESB requirements that describe what is considered being compliant with R10.13, posting ATC, ETC, TTC. Not the "what" requirement but the "how" requirement.

M2

1.Do we need to be compliant with the requirements of MOD-030 (selected ATC Methodology) or are we audit against the description of ATCID Document

M7

1. Same question as listed under R8.

.

MOD-004-1

R5

1.We think this should be a TSP responsibility and not a TP responsibility. What is reason this was assigned to Transmission Planner.

MOD-008-1

R1 and R2

1.What is the reasoning behind making TSP responsible for the ATCID Document and CBMID document and making TOP responsible for TRMID Document. We think TRMID should be a TSP responsibility also.

MOD-030-1

R2

1.What is the reasoning behind making TOP solely responsible to identify flow gates. We think both TSP and TOP are responsible, TOP for his Operating Area and TSP for the Tariff footprint and neighboring footprints.

R3

1.What is the reasoning behind making TOP responsible to maintain a transmission model to determine AFC. We think TSP should be responsible, to model the Tariff footprint and neighboring footprints as complete as possible.

R4.2

1.What is the reasoning behind requirement of higher granularity for AFC Calculations. (using Source and not POR). We think it should be allowed to calculate impacts on POR / POD basis (grouping of commonly dispatched resources within BA Area) and not with higher granularity. (Source) It is not required to schedule the Confirmed Reservation with same granularity.

2.What is meant with "interface points with adjacent TSP". The 1tier BA Area of TSP?

R5.2

1.What is definition of external (third party) flow gate. Is it something like: third party flow gate is flow gate for which the limiting equipment of the monitored element is not in one of the TOP Areas of the Tariff footprint of the TSP.

2.What if RC footprint doesn't match the Tariff footprint. Are we required to use AFC overwrite from some one else if it is our RC flow gate however not our Tariff flow gate.

R6.2

1.What is the definition of "expected to be scheduled". Does this mean TSP can use judgement ?

2.What is the definition of "Included in de model ", probably refers to included in calculations referred to in R6.1.1 – R6.1.4

R9

1.MOD-001-1 requires posting of ETC. If a TSP uses Flowgate Methodology does he need to convert ETC (flow gate based) to ETC (path based) using same formula as R9. Or does he need to post ETC flow gate based, result of R7 and R8 requirements of MOD-030-1.

M2

1. See R2 question..

M7

1. See R3 question.

M10

1. What about using outages for Monthly time frame? We only use outages if they last more than 15 days in that Month.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Anita Lee | |
| Organization: | Alberta Electric System Operator | |
| Telephone: | 403 539-1497 | |
| E-mail: | anita.lee@aeso.ca | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

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**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

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**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
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Comments:

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Comments: The AESO currently does not use OASIS for transmission services but is sharing information with the British Columbia Transmission Corporation for posting transmission services on the only one shared tie line. To meet some of the requirements in these standards that require the entity to post transmission information (such as ATCID) on OASIS, would it be acceptable for such entity to post the information on its website instead? Could this provision be added to the requirements?

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|---|---|---|
| Name: | Warren Clark | |
| Organization: | Avista Corporation | |
| Telephone: | 509-495-4186 | |
| E-mail: | warren.clark@avistacorp.com | |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
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| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☒ Yes

☐ No

If "Yes," please identify your concerns. Comments: Avista strongly supports the inclusion of a 12-month implementation period for these standards. A 12-month implementation period is particularly important for MOD-29. MOD-29, as drafted, will require that numerous paths not previously exposed to the high rigors of the MOD-29 TTC determination process will have to be examined. Avista anticipates that it will elect the Rated System Path Methodology for certain Posted Paths on Avista's system. Avista will, at a minimum, require a 12-month implementation period to assure proper review of the Posted Paths under the methodology. It will be difficult, if not impossible, to fully implement MOD-29 in the absence of the recommended 12-month implementation period.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: In MOD-001, "Posted Path" is included as a defined term. "Posted path" is also defined in 18 CFR § 37.6 (b)(1)(i). Using a term that is already defined in the CFR may create confusion. Accordingly, Avista suggests that throughout the MOD standards, NERC replace the term "Posted Path" with a different defined term, such as "paths required to be posted", "paths requiring posting" or "paths for which ATC is calculated."

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☐ No

If "Yes," please explain why and provide supporting information.

Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: MOD-001-1, A., 3. the stated purpose contains goals that are not required for reliable system operation, but rather are for viable commercial activity. Reliable system operations are impacted by incorrect TTC values and uncoordinated transaction scheduling activities.

MOD-001-1, A., 4. Applicability, Transmission Service Providers calculate ATC. Transmission Operators (in the near term) and Transmission Planners (in the longer term) calculate TTC.

MOD-001-1, B., R1, Transmission Operators calculate transfer capability (TTC) of facilities within their TO areas. Transmission Planners calculate transfer capability (TTC) of facilities within their TP areas. Transmission Service Providers calculate ATC for those paths that they are required to, choose to, or are asked to post.

MOD-001-1, B., R3 Transmission Service Providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability. This requirement to create a separate document creates an undue burden on the industry - transmission customers will have two different documents to review, and transmission service providers will have two different documents to maintain.

MOD-001-1, B., R3.3 the term “Facility” should say "Posted Path" (but see the comment above regarding definition of "Posted Path"). The term facility in the NERC glossary says facility is “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).”

MOD-001-1, B., R3.6 “Allocation methodologies” – it is not clear to what this means? Perhaps the following: "For paths where multiple Transmission Service Providers share capacity or have rights, describe how the capacity is allocated among providers," or words to that effect.

MOD-001-1, B., R4 is not needed, it is already covered in R3.2.

MOD-001-1, B., R5 is not needed, it is already covered in R3.2.

MOD-001-1, B., R6 is not necessary. Revisions to Attachment C are to be filed and posted.

MOD-001-1, B., R7 Attachment C is already required to be posted (available) for any entity to review, subject to CEII concerns.

MOD-001-1, B., R9 is not a reliability concern. In addition, it is unduly burdensome. Current and accurate ATCs are a commercial concern. In addition, performing 168 hourly calculations every hour when neither TTC nor ETC has changed, benefits no one and is costly. The commercial requirement should be to require the recalculation of hourly ATC once a day and whenever either TTC or ETC changes for any period of time between this hour and the next 168 hours.

MOD-001-1, B., R10, this requirement for data sharing between reliability entities is a good concept. However, as currently worded, all the burden to supply data is incorrectly placed totally upon the TSP and not on the Transmission Operator or Transmission Planner. Much of the data listed is critical for proper TTC calculation which the TSP may not have access to. The TSP calculates ATC based on upon TTC supplied by the Transmission Operator and/or Transmission Planner. This requirement does not specify how the request is made or how the response or provision of data is dated. The corresponding measurement, M9, implies that all data items requested will be supplied within 14 days, but requirement states that the TSP will begin to make available at the 14 day mark. In addition, change first sentence words "…days of a request of any Transmission…" to "…days of a request made by any Transmission…" to read more in-line with the intent.

MOD-004-1, A., Capacity Benefit Margin is a use of the transmission system that is requested by a load serving entity. This standard contains requirements for the interactions between the LSE and the transmission provider. These requirements are largely commercial in nature and should be under NAESB development. Reliability standards concerning CBM should only require LSEs to acquire minimum CBM to ensure service to load.

MOD-004-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider's CBM methodology. This requirement to create a separate document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and providers would have to maintain two different documents.

MOD-004-1, B., R2 is not necessary. Revisions to Attachment C are to be filed and posted (available) for any entity to review, subject to CEII concerns.

MOD-004-1, B., combine R3.3 language into R3.1.

MOD-004-1, B., R3.2 it seems more reasonable for the requirement to read "LSE shall review any active CBM requests at least every six months and submit updates as required."

MOD-004-1, B., R8, R9, R10, M11, M12, M13 use of the terms "tag" or "Interchange Transaction Tag" which is inconsistent with NERC INT and NAESB CI BP standards where specific reference to "tag" or "e-Tag" has purposefully been avoided in those standards. The term Request For Interchange (RFI) refers to a collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink BA. Or the term Arranged Interchange refers to The state where the Interchange Authority has received the Interchange information (initial or revised) and has distributed that information for reliablity assessment. I believe that in these requirements, Arranged Interchange is the more appropriate langauge.

MOD-008-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider's TRM methodology. This requirement to create a separate document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and TSPs two different documents to maintain.

MOD-008-1, B., R1.1 suggest modifying to read: "For each path or flowgate that ATC or AFC is calculated, describe how each of the following components of uncertainty are used in calculating TRM for each of the ATC time horizons (if not applicable, indicate as such):" The words "ATC time horizons" could be used to eliminate the need for R1.4.

MOD-008-1, B., R1.1 suggest adding another item to the list. Variability and uncertainty in determining Transmission losses across Posted Paths.

MOD-029-1, B., R1 (modeling requirements) should include the statement that the data listed below should relfect the expected conditions for the applicable time period.

MOD-029-1, B., 1.6 Suggests this bullet be deleted. This is already addressed in R2 wherein the modeling process is dictated. In the RSP methodology, "peak load forecasts" are not used to stress the system; rather, load and generation are simulated to stress the system to its greatest capacity. There are cases when the highest forecasted load may not stress the system to its greatest utilization – which is the goal of the R2 under the RSP.

MOD-029-1 B., R5 definition of GF - The language describing Grandfathered capacity includes the defined terms "Firm" and "Transmission Service." Use of these words as defined terms is inconsistent throughout the proposed standards. They should either be changed here to a lower case or all applicable areas in each proposed standard should be changed to the defined term.

MOD-029-1 in R6, is the "non-firm capacity reserved for NITS" the same as Secondary Network Service (i.e., NN-6)?

MOD-029-1 in R7 & R8, what are "Postbacks"? This term is not used in the west. The term Postback should not be used in the RSP methodology.

MOD-029-1 in R5, R6, R7, & R8, calculation of ETC and ATC are commercial concerns and should be addressed in business practice standards NAESB and enforced through FERC's adoption of those business practice standards into the CFR.

MOD-029-1 in R8 ETC (Firm) definition, it uses the word "non-firm" and it should state "firm". We are assuming this is a typo.

MOD-029-1 in R8 the requirement says we are to use the same formula for all horizons – this is incorrect. For the real-time, same-day time frame, we release all unscheduled capacity as non-firm ATC. As such, the formula would read:

ATCNF = TTC – Scheduled ETCF – Scheduled ETCNF – CBMS – TRMU + Counter-schedulesF + Counter-schedulesNF

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RELIABILITY CORPORATION

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Jerry Smith | |
| Organization: | Arizona Public Service Co. | |
| Telephone: | 602-250-1135 | |
| E-mail: | jerry.smith@aps.com | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
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# Arrangement of Requirements within the Proposed Set of 'ATC' Standards

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- ATC Implementation Document
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- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

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- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

## Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

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The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

   ☐ Yes

   ☒ No

   If "Yes," please identify your concerns. Comments:

   Arizona Public Service Co. strongly supports the inclusion of a 12 month implementation period for these standards.

2. If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

   Incorrect Definition: Arizona Public Service Co. agrees with the WECC's Comment that the NERC ATC Drafting team should clarify the meaning of the term counterflows.

   In addition the NERC ATC Drafting team should clarify what is meant by the term post back.

3. If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

   Incorrect Requirement: • Arizona Public Service Co. is in agreement with the WestConnect Comments and in general agreement with the WECC Comments.

4. The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

   Incorrect Measure or Compliance Element:
   Arizona Public Service Co. is in agreement with the WestConnect Comments and in general agreement with the WECC Comments.

   In addition the Arizona Public Service Co. adds the following comment.

   MOD-001
   The use of Counter Schedules to create firm ATC is of concern to APS. This practice could result in unreliable conditions to the interconnection if the counter flows do not occur. Due to the reliability concerns there should be a requirement for the Transmission Provider to provide documentation of actions that it will take if the Counter Flows do not occur.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: Arizona Public Service Co. is in agreement with the WestConnect Comments and in general agreement with the WECC Comments.

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Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Eugene Warnecke | | |
| Organization: Ameren Services | | |
| Telephone: 314-554-2762 | | |
| E-mail: EWarnecke@ameren.com | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
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**Contact Organization:**

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**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
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    - ETC (firm and non-firm)
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*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

   ☐ Yes

   ☒ No

   If "Yes," please identify your concerns. Comments:

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   Incorrect Requirement: MOD-004-1

- R4.2. This is a fundamental mathematical analytical dichotomy. The CBM component is based on probabilistic LOLE/LOLP style analyses that look at aggregate probability loss. The reserve sharing component of TRM is deterministic. It is imprudent to combine these as they are not derived from the same methodology except in the rare case where the generation is sufficiently constrained that the only resulting generation left after CBM event is the reserve sharing generation.

- R4.2.2. Since AFC is determined from CBM, CBM for each Flowgate should not be dependent on AFC. CBM can be big enough to drive AFC to zero or negative. This simply means that resource adequacy criteria can't be met, and no capacity will be available on that Flowgate (which is what the original wording of this requirement was trying to do anyway). Therefore CBM should not be set to AFC, it should be left at whatever value was calculated. This concept applies to R4.2.1 and R5.2 as well.

  R4.3 and R5.3 Not necessary. Refer to R4.2.2 for explanation.

4. The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

   Incorrect Measure or Compliance Element: MOD-004-1
   M8. "CBM has been used to determine a margin" should be reworded. CBM is a margin. Suggest eliminating "to determine a margin".

   D.1.3. R1 refers to CBMID not ATCID.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

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Comments: MOD-004-1

6. Effective Date: "all six standards are approved" MOD-001-1 lists the six standards, should list here as well.

R4.1.2.2. "each impacts" => "each impact"

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| Organization: | American Transmission Company | |
| Telephone: | 262 506 6885 | |
| E-mail: | jshaver@atcllc.com | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☒ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
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Group Comments (Complete this page if comments are from a group.)

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**Lead Contact:**

**Contact Organization:**

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- Follow counterflow rules
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- Share ATC data and information

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- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
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- Modeling requirements
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Comments: MOD-001-1 – Available Transfer Capability

R1: Potential source of problems – the Transmission Operator (American Transmission Co.) selects an ATC methodology that the Transmission Service Provider (Midwest Independent System Operator) must use for calculations even if it is not equipped to use the methodology chosen. May want to add language that urges agreement between TO and TSP.

MOD-004-1 – Capacity Benefit Margin

R2: Typo in line two, "CBID" should be "CBMID"

R4.1.2.2: Should be rewritten. Suggestion: "Impacts with a Distribution Factor of 3% or greater relative to OTDF Flowgates and 5% or greater relative to PTDF Flowgates will be classified as significant."

R4.2: CBM should not be based on the sum of all requests – we don't need to plan for a simultaneous capacity emergency in every area impacted by a Flowgate. Rather, CBM should be based on the maximum of all requests. By reserving the maximum CBM of all requests, a single capacity emergency in any one area impacted by the Flowgate will be covered.

R4.2.2: Setting CBM to the lesser of the GCIR impacts or the firm AFC for a Flowgate is not correct, because setting CBM based on AFC or ATC is an invalid circular argument. Consider the following simple example:

The definition of AFC:TFC – EFC – CBM –TRM + Postbacks + Counterflows = AFC

So, if the rating on a Flowgate is 100 MW (TTC = 100),

there are no existing transmission commitments (ETC = 0),

the calculated GCIR impacts is 25 MW (CBM = 25),

and for the sake of this example there is no Transmission Reliability Margin (TRM = 0),

and no Postbacks or Counterflows.

Our AFC:

$$100 - 0 - 25 - 0 + 0 + 0 = 75$$

Now assume that firm sales account for 75 MW of flow across the Flowgate, so ETC = 75.

New AFC:

$$100 - 75 - 25 - 0 + 0 + 0 = 0$$

So in this case, we've got an AFC of zero, which is less than the calculated GCIR, so we would set CBM to zero even though we previously set aside 25MW for CBM that is being unused!

CBM should be set to the calculated maximum GCIR value for the impacted LSE's. As CBM fluctuates up and down year-by-year the AFC will be affected and may sometimes go negative, but this is a necessary by-product of selling transmission service (ETC) far into the future.

R4.3: CBM should not be reduced based on insufficient capacity. If AFC/ATC happens to be negative when a request to use CBM is issued, the CBM transactions should be granted and then all transactions across the constrained element, including the CBM transactions, should be curtailed on a pro-rata basis, which will result in load shedding procedures for the capacity deficient entity. This is the next step in an Energy Emergency Alert. CBM is the last attempt in EEA2 to prevent EEA3 and firm load curtailment.

R5.2: Change sum to maximum, see note for R4.2.

MOD-008-1 – Transmission Reliability Margin

R1.5: Typo in line one, change "all" to "any."

R4: Shouldn't the Transmission Operator also have the right to request this information? This requirement only allows other TSP's to receive the TRM calculation info.

MOD-030-1 – Flowgate Methodology

R2.1: Typo in line one, change "used" to "use."

R3: Change "Transmission Operator" to "Transmission Service Provider" because MOD-001 requires the TSP to calculate ATC/AFC values.\

R8: Typo in counterflows section, change "ATC" to "AFC"

R9: Typo, "ATCNF" should be "AFCNF"

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
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| Organization: | Bonneville Power Administration | |
| Telephone: | (360) 619-6421 | |
| E-mail: | ajnulph@bpa.gov | |
| **NERC Region** (check all Regions in which your company operates) | | **Registered Ballot Body Segment** (check all industry segments in which your company is registered) |
| ☐ ERCOT | ☒ | 1 — Transmission Owners |
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The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.
- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.
- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.
- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.
- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.
- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004
- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004
- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments: This allotted time is sufficient and if shortened, would be a burden, especially for those entities electing to use the Rated System Path methodology that will require a much more rigorous TTC determination process than has historically been used.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

- Incorrect Definition:
- a. A definition for counterflow should be provided and used consistently in MOD-028, -029, and -030. A suggested definition follows: "Counterflow: the impact of schedules, reservations, or actual flows of energy in the direction opposite to the constraint."
- b. MOD-004 – In Order 890, FERC limited the use of CBM to meet generation reliability criteria – please clarify what is meant by "reserve adequacy requirements"

c. MOD-029 – The definition of Rated System Path Methodology incorrectly refers to ATC as "Available Transmission Capability" – this should be corrected to "Available Transfer Capability"

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

- Incorrect Requirement:
- a. MOD-001
- i. R1 and R2 – "time periods" should be replaced with "time horizons"
- ii. R3.2 – "counter-schedules" should be deleted and "counterflows" should be capitalized with the definition supplied above [Counterflow: the impact of schedules, reservations, or actual energy flows in the direction opposite to the constraint
- iii. R3.3 – BPA suggests removal of this requirement, as it would require extensive modification to existing databases without serving a great need.
- iv. R4 and R5 – should be cut from MOD-001 and placed in MOD-028, -029, and -030

- v. R10 – The wording is confusing and should be modified to the following: "…current versions of the following data, limited to that data requested, in electronic format…"
- vi. R10.2 – "Peak" should be deleted, as non-peak load forecasts may be used in ATC calculations
- vii. R10.3 – BPA requests that the term "Block dispatch" be defined
- viii. R10.4 – Should be modified to the following, to be less vague and more consistent with the pro-forma OATT: "Aggregated capacity encumbered for Network Integration Transmission Service and Secondary Service"
- ix. R10.6 – Should be modified to the following, to allow for the inclusion of Grandfathered service or other statutory obligations that have not been contracted for: "Aggregated capacity encumbered for Grandfathered obligations"
- x. R10.13 – It appears as though the following is missing from the last right parenthesis: "(TRM"
- b. MOD-004
- i. R1 – Should have a fourth sub-requirement added to explain that if there is insufficient capacity available to satisfy all requests for CBM, the Transmission Service Provider shall explain in its CBMID how allocation of CBM will occur
- ii. R2 – Should be modified to the following: "…CBMID to the Transmission Operator, adjacent Transmission Service Provider…"
- iii. R8 – Should be modified to the following: "…set aside as CBM unless affected by a declared NERC Energy Emergency Alert (EEA) 2 or higher"
- c. MOD-029
- i. R1.4 – "Non-regulating" should not be capitalized
- ii. R1.6 – "peak" should be deleted, as non-peak load forecasts may be used in TTC calculations
- iii. R1.12 – "ACTID" should be changed to "ATCID"
- iv. R2.2 – There appears to be a potential discrepancy between this requirement and other reliability requirements for establishing System Operating Limits.
- v. R2.3 – "R1.2.1" should be changed to "R2.1"
- vi. R5 – "reserved" should be changed to "encumbered" in the description of NL, GF, and OS, as these obligations may not have been reserved via an OASIS transaction – Additionally, the "Firm Transmission Service" in the description of GF should not be capitalized
- vii. R6 – "reserved" should be changed to "encumbered" in the description of GF and OS, as these obligations may not have been reserved via an OASIS transaction –

Additionally, the "Transmission Service" in the description of GF should not be capitalized

- viii.R7 and R8 – "Counter-schedules" should be changed to "Counterflows" with the definition supplied above [Counterflow: the impact of schedules, reservations, or actual flows of energy in the direction opposite to the constraint]

- ix. R8 – "non-" should be deleted from the description of ETC

- d. MOD-030

- i. R2.1 – Delete "for" after "Flowgates"

- ii. R2.1.1 – BPA suggests the following clarification to this requirement, to avoid posting unnecessary data: "Any Facility within the Transmission Operator's area based on thermal, stability or voltage limits is a Flowgate if such limits reduce transfer capability on a Posted Path

- iii. MOD-001 allows an entity to select multiple methodologies to determine ATC. For example, an entity may elect to use Flowgates inside their affected area whereas they may also elect to use the Rated System Path Methodology at the interface of their affected area. Under this scenario, the applicable entity need not study Flowgates beyond the intercepting cut plane of its interface as the ATC at the interface falls not under MOD-030, but MOD-029. To prevent unneeded seams issues, the following rewrites are suggested:

- 1. R2.1.2 – All first Contingency transfer analyses from all adjacent Balancing Authority source sink combinations such that at a minimum the first three limiting Elements/Contingency combinations within the Transmission Operator's system are included as Flowgates, unless the interface between such adjacent Balancing Authorities is accounted for using the Rated System Path Methodology

- 2. If adopted, similar language should be applied to R3.5, R3.6, R5.1, R6.1, R6.3, R6.4, R7.2, and R7.4

- iv. R4 – "Use" should not be capitalized – Additionally, two sub-requirements should be added to allow for the modeling of impacts of Network Integration Transmission Service and Grandfathered service in the base AFC calculations.

- v. R6.1 – "Firm Network" should be changed to "Network Integration Transmission Service" to be consistent with how this service is identified in the OATT

- vi. R6.1.1.1, R6.1.2.1, R6.1.3.1, and R6.1.4.1 – "Peak" should be deleted, as non-peak load forecasts may be used in ETC calculations – Additionally R6.1.3.1 is incorrectly identified as "R6.1.3.1.1"

- vii. R6.3 – The last sentence should be a separate requirement, similar to R7.3 – this would result in the final sentence of R6.3 becoming R6.4 and the current R6.4 becoming R6.5. The new R6.4 and R6.5 should also be modified to the following to accommodate Grandfathered service or other statutory obligations for which a contract does not exist or scheduling requirements are not in place: "The impact of any firm Grandfathered obligations expected to be utilized…"

- viii.R7.3, and R7.4 – Each should have the word "contracts" replaced with "obligations" to accommodate GF service that does not hold a contract.

  ix. R7 – A sub-requirement should be added to allow for the inclusion of the impacts of Network Integration Transmission Service and Secondary Service

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:
a. MOD-01
i. M9 – There is an unnecessary word "the" following the word "show" in the second line of the measure. Additionally, the timeline(s) for responding to a request for data in R10 and M9 should be made consistent with one another – is it a requirement to respond to the request for data w/in 14 days or to begin to respond?
ii. VSL for R4 – The word "Firm" should be inserted before the word ATC as R4 only refers to Firm ATC.
iii. VSL for R5 – The word "Non-Firm" should be inserted before the word ATC as R5 only refers to Non-Firm ATC.
b. MOD-04
i. M1 – Suggested rewording: "Each Transmission Service Provider shall produce its CBMID evidencing inclusion of all specified information in R1." This approach should also be taken at M1 for MOD-08.
ii. M5 – line 3 states "…they it has based its CBM…" Please change to "…that it has based its CBM…"
iii. VSL for R2 – The acronym "CBID" should be changed to "CBMID."
iv. VSL for R10 – The VSL is unclear. The Team suggests it be rewritten to state, "The Transmission Service Provider failed to approve an Interchange Transaction Tag for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available."
v. D1.3 Data Retention – For clarity, the phrase "three calendar years" in the second through fifth bullets should be changed to "most recent three calendar years plus the current year."
c. MOD-08
i. M5 – M5 is missing he right parenthesis after the word "data" on the first line.
ii. VSL for R1 – In the Moderate Level column, change the phase "changes been" to "changes that have been".
d. MOD-29
i. M1 – M1 inaccurately calls for production of "models" used to derive TTC. As there are multiple conditions under MOD-29, R2 where a model does not dictate the predicate for TTC, M1 should be reworded to state "…shall produce the models, contracts, nomograms, reports or study results…" – this corresponding to:
1. Models in R2.1, R2.2. and R2.5
2. Contracts in R.2.3 and R2.6
3. Nomograms in R2.4
4. Reports or studies in R2.7 and R2.8
ii. M1.3 – The Team suggests correcting M1.3 from "…as stated in R1.1 through R.12…" to "…as stated in R1.1 through R1.12…"
iii. M4 – If "M1" above is adopted, M4 is duplicative of M1 and should be deleted.
iv. VSL for R4 – An SOL does not exist for every Posted Path. This VSL should be amended by changing the words "the SOL" in the High and Severe columns to read "any

SOL". This makes the wording of the Requirement consistent with the wording of the Measure.

v. VSL R5, R6, R7, R8 – These VSLs call for only a "severe" determination. They also mandate that the TSP "use" all the elements defined. However, the TSP will not "use" all the defined elements if they are not applicable. Thus, if a TSP does not "use" all elements defined because all the elements were not applicable – the TSP is in violation for not including null elements in its calculation. The Team suggests these be rewritten to state: "The Transmission Service Provider did not use all affected elements as defined in…." This approach should help clarify that "zero" as an integer is an acceptable entry and that only those variables "affected" need be reported or acted upon.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.

Comments: This response, however, is based on the understanding that BPA's statutory requirements to serve the load of other federal entities (i.e. the Corp of Engineers and the Bureau of Reclamation) are sufficiently accommodated within the GF or OS components of the ETC calculation in MOD-029 and the GF component of the ETC calculations in MOD-030. If these variables were not intended to accommodate non-contracted statutory obligations of this nature, please modify the ETC calculations to accommodate these obligations (see suggested modifications provided in earlier comments).

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

a. GENERAL

i.BPA supports retention of the three methods recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028).

ii.BPA supports the retention of the proposed one-year implementation period.

iii.BPA supports allowing NAESB to address all "posting" issues as they directly affect OASIS.

b. MOD-001

i.BPA supports allowing the use of more than one methodology for calculation of ATC by any one entity. For example, the Team supports allowing any entity to use the Flowgate methodology inside their affected area while also using the Rated System Path methodology at its boundaries.

ii.BPA supports allowing each entity to specify in its ATCID how it will treat counterflows.

iii.BPA supports the aggregation of transmission capacity for grandfathered contracts when shared with neighboring requestors.

iv.BPA supports the specifically limited universe of entities to which data sharing is required as prescribed in R10.

c. MOD-008

i. R2 – Add the following language to strengthen the distinction between TRM and CBM: "Transmission capacity required for the period immediately following a contingency and before the market can respond (up to 59 minutes following the contingency) are included in TRM"

d. MOD-029

i. BPA strongly supports retention of the requirement(s) in R2.2 that accommodate paths which are "flow limited" by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing and functional practices without re-inventing the wheel where no such effort is required to meet FERC's goals of transparency and consistency.

ii. BPA strongly supports retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.

iii. BPA strongly supports retention of the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.

iv. BPA strongly supports retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts and potentially their associated operational agreements while supporting FERC's mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation methodologies is required.

v. BPA strongly supports the adoption of the proposed Counterflow definition as its adoption clarifies the application of Counterflows in each equation.

e. MOD-030

i. R10 – It is assumed this requirement has been included to promote transparency, but will in fact have the opposite effect due to a flood of posted data being required that is not used to process requests, and therefore is not used by market participants, and should be modified to the following: "The Transmission Service Provider shall provide a tool to convert…"

BPA has heard from a number of its Customers and other impacted parties that the posting of ATC, rather than AFC, will not promote transparency in the Northwest market or across BPA's system. BPA provides several tools on its website and OASIS site to facilitate interested parties' access to AFC-to-ATC conversions. These tools are easy to use and since a smaller quantity of data is posted to our OASIS site (i.e. 10 AFCs as opposed to several thousand ATCs), our OASIS system is more responsive and therefore, also easier to use.

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Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Phil Park | |
| Organization: | British Columbia Transmission Corporation | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☒ Yes

☒ No

If "Yes," please identify your concerns. Comments: We have two concerns, discussed in our comments below, that if not addressed may be problematic for a 12 month implementation, as BCTC may have difficulty in achieving compliance with any of the three ATC methodologies within 12 months. Our first concern is discussed in our comment 6.3 below regarding MOD-028-1, R7. MOD-028-1 will not be an option for BCTC if we cannot continue to use interpolation between representative TTCs (that we calculate according to the process described in R7). It will take BCTC longer than 12 months, if it is even practical, to develop the systems to calculate TTC with the same level of accuracy as we do today without interpolation, given the complexity of our system, the range of variable, limitations, and contingencies we consider to determine TTCs. Our second concern is discussed in our comment 6.5 with respect to MOD-029-1 M-1. We believe that this requirement is redundant to M4. However, if it is retained as a specific requirement to produce models, BCTC will have a problem because it appears to retroactively require that models be produced for TTC calculations that were done in the past, and such models are no longer archived. BCTC does not use flowbased methods, so MOD-030-1 is not applicable to us. For these reasons, for BCTC to be compliant within 12 months, it is important to us that the concerns described above and discussed further in our comments 6.3 and 6.5 be accommodated within the standards.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

1. MOD-001-1, R3.3 - The word "Facility" should be replaced with "Posted Path".

2. MOD-029-1, R1.6 - We suggest that the word "peak" be removed. Often maximum TTC occur at off-peak conditions when load near to the generation is lower.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect,

please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

1. MOD-029-1, M4 and Compliance, 1.3 Data Retention, 4th bullet - The reference to R2.7 should be R2.6 (i.e. should be R2.1 through R2.6). There are no models, reports, or study results required by R2.7. Therefore, there is no point in having a Measure and a Compliance Process looking to see if models, reports, or study results have been produced and retained.

2. MOD-029-1, M7 - Should the reference be to R7 and R8? R6 does not require the use of TTC.

3. MOD-029-1, M7 - The reference to R.1.2 is not clear. Should this reference be to R2?

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

1. MOD-028-1, R3.1 - We believe we understand the meaning of intra-day but are unfamiliar with the term intra-peak. Does this mean hourly peak?

2. MOD-028-1, R3.1, R3.2, R4.1, R4.2 - The parenthetical "(at a minimum)" is subject to interpretation. Does it mean that this is the minimum list of parameters to model or does it mean that these are the most conservative values allowed? If additional parameters or some other values are used, the references need to be specified somewhere. For example, if Peak Load is not used (because a higher TTC can be made available in shoulder hours), the ATCID needs a section describing what load to use. We suggest that "(at a minimum)" be replaced with "(or other values and additional parameters as specified in the ATCID)".

3. MOD-028-1, R7 - The process for calculating TTC should also the Transmission Operator to calculate TTC by interpolating between TTC values that have been calculated according to the process outlined. In complex systems with many assumptions in variables (e.g. load forecast, ambient temperature, generation dispatch), many possible limitations (e.g. thermal, transient stability, voltage stability, minimum voltage), and many single and multiple contingencies to run, it becomes impractical to calculate TTCs as described in R7. BCTC currently runs up to N-3 contingencies. BCTC, as well as an adjacent Transmission Operator, calculate TTCs using the process described in R7 for representative conditions, which on there own can require thousands of studies. TTCs for other conditions are then found by interpolation between the representative cases. Any margin we need to allow for "interpolation error" is much less that the margin we would need to allow if we generalize generation dispatch, ignore transient stability, or

omit multiple contingency studies. Under no conditions do we extrapolate outside of the conditions bracketed by the studies. We propose an item f be added as follows:

f. When two or more transfer capabilities have been established according to the above procedure which bracket the requirements described above, the TTC can be determined by interpolation between these established transfer capabilities.

4. MOD-029-1, R4 - The double use of TTC is potentially confusing. At a minimum we suggest rephrasing R4 to be "at the lesser of the TTC calculated in R1".

5. MOD-029-1, M1 - This measure is redundant. M4 requires that the TO produce the models, reports, or study results that it used to establish TTC. Since M4 already addresses models, M1 is redundant.

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Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

<table>
<tr><th colspan="3">Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name: K. David Hagen, General Manager</td></tr>
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<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment<br>(check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☐ NPCC<br>☐ RFC<br>☐ SERC<br>☐ SPP<br>☒ WECC<br>☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
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</table>

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

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**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

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The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information ‘publicly available’ – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

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**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

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**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

2) In reference to MOD-030-1/R10, the requirement should be altered as follows: "The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC's for its network and provides a tool for AFC-to-ATC conversion (in BPA's case, Power Utilization Factor Calculators). We believe at this time that this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Paul Arnold --Vice President | |
| Organization: | ColumbiaGrid, Inc. | |
| Telephone: | 503-943-4933 | |
| E-mail: | arnold@columbiagrid.org | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** **ColumbiaGrid coordinated these coments with its members and parties to its functional agreements , including Avista Corporation, Bonneville Power Administration, Public Utility District No. 1 of Chelan County, Public Utility District No. 2 of Grant County, Puget Sound Energy, Seattle City Light, Tacoma Power, and Snohomish County PUD, as well as many other interested parties throughout the Northwest region of the WECC. These entities may provide their own separate comments, which may or may not agree with ColumbiaGrid's comments.**

**Lead Contact:** **Paul Arnold**

**Contact Organization:** **ColumbiaGrid, Inc.**

**Contact Segment:**

**Contact Telephone:** **503-943-4933**

**Contact E-mail:** **arnold@columbiagrid.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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**(ATC)**

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- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
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    - ETC (firm and non-firm)
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- Share TTCs

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**Flowgate Methodology**

- Method-specific ATCID elements
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☐ Yes

☐ No

If "Yes," please identify your concerns. Comments: [Intentionally left blank.]

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Comments: [Intentionally left blank.]

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: Please see the comments below.

GENERAL COMMENTS:

a) ColumbiaGrid, a non profit corporation formed to promote the efficient operation, planning and use of the Northwest transmission grid, is generally supportive of the ATC Reliability Standards comments prepared by WECC. ColumbiaGrid believes that it is important to recognize and address the distinctive characteristics of the Western interconnected transmission grid. It should be noted that ColumbiaGrid has not attempted to address or comment on questions one through five, which address the specific language of the individual standards. ColumbiaGrid submits these general comments on its own behalf, not on behalf of its members or other participating parties, each of whom may submit general or specific comments on its individual behalf.

b) ColumbiaGrid supports the inclusion and need for all three ATC methodologies, recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028). ColumbiaGrid believes that retention of all three ATC methodologies is necessary to ensure that differences in structure and operation of regional and individual transmission systems are accurately and efficiently accommodated.

c) MOD-029 – ColumbiaGrid supports the need for this methodology, which is commonly utilized in the Western region.

d) MOD 030 - R10:

R10 states that the TSP shall convert Flowgate AFCs to ATCs for Posted Paths. Posted Paths is defined in MOD 1 as:

1. Any Balancing Authority to Balancing Authority interconnection;

2. Any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 month;

3. Any path for which a Transmission Customer requests to have Available Transfer Capability or Total Transfer Capability posted.

ColumbiaGrid is concerned that posted paths, as used in R10, could mean that AFCs must be converted to ATCs for any constrained POR/POD combination. ColumbiaGrid understands that this requirement has been included to promote transparency, but it may in fact have the opposite effect due to a flood of posted ATCs that are not used to process requests and of little value to transmission customers. BPA has provided a better alternative than converting AFCs to ATCs on constrained POR/POD combinations. BPA posts AFCs on internal flowgates and provides a tool for its customers to calculate the flow imposed on the flowgate relative to the POR/POD. ColumbiaGrid understands that BPA has heard from a number of its Customers and other impacted parties that the posting of ATC, rather than AFC, will not promote transparency in the Northwest market or across BPA’s system. Further, ColumbiaGrid understands that BPA provides several tools on its website and OASIS site to facilitate interested parties’ access to AFC-to-ATC conversions. These tools are easy to use and since a smaller quantity of data is posted to BPA’s OASIS site (e.g. approximately 10 AFCs as opposed to potentially several thousand ATCs), BPA’s OASIS system will likely be more responsive and therefore, also easier to use. ColumbiaGrid believes that this method eliminates burdensome postings of multiple POR/POD ATCs.

ColumbiaGrid proposes that R10 be modified as follows: “The Transmission Service Provider shall provide a tool to convert AFCs to ATCs for posted paths…”

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| **Individual Commenter Information** | | |
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| **(Complete this page for comments from one organization or individual.)** | | |
| Name: Roman Gillen | | |
| Organization: Consumers Power, Inc. | | |
| Telephone: 541-929-8500 | | |
| E-mail: romang@cpi.coop | | |
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- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

2) In reference to MOD-030-1/R10, the requirement should be altered as follows: "The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC's for its network and provides a tool for AFC-to-ATC conversion (in BPA's case, Power Utilization Factor Calculators). We believe at this time that this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Greg Rowland | |
| Organization: | Duke Energy | |
| Telephone: | 704-382-5348 | |
| E-mail: | gdrowland@dukeenergy.com | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☐ | 5 — Electric Generators |
| ☒ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☒ Yes

☐ No

If "Yes," please identify your concerns. Comments: Increased recalculation frequencies will require implementation of new methods and tools. Suggest effective date of 18 months after applicable regulatory approvals.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

- MOD-001-1, R5.2 should say "approved Interchange Transaction Tags" instead of "schedules".

- MOD-001-1, R9 should say "recalculate" rather than "update".

- MOD-001-1, R10 should allow 30 days instead of 14 days to make data available after a request, since setting up the required data exchange protocols will be time-consuming.

MOD-004-1, R3.1.1.2 should be revised to require a monthly GCIR value for each month during the current year and the following two years for each Balancing Authority or Posted Path.

MOD-004-1, R3.2 should be revised as follows: Pursuant to the frequency established in the Transmission Service Provider's CBMID, update the request provided per 3.1 to reflect any changes that alter future needs for CBM or indicate that no change is needed.

- MOD-004-1 Requirements:
- R3.2 At least every thirty-one days, update the request provided per R3.1 to reflect any changes that alter future needs for CBM or indicate that no change is needed.
- M4. The Load-Serving Entity that wants CBM shall provide dated copies of its updated CBM requests as evidence that it has updated its CBM request or confirmed no update was needed at least every thirty-one days, per R3.2 (R3).

- VSLs tied to this measure increase in severity due to change in GCIR. (e.g., Moderate VSL is tied to failure to update and Generation Capability Import Requirement had changed by more than 20MW or 10%, whichever is smaller, and not more than 30MW or 20%, whichever is smaller. Severe VSL is tied to failure to update and Generation Capability Import Requirement had changed by more than 40MW or 30%, whichever is smaller.)
- Duke Comments:
- 1. There is no basis in Order 890 for this requirement of updating every 31 days. This creates an unnecessary administrative burden on the Transmission Provider, the Transmission Planner, and the Load-Serving Entities.
- 2. The VSLs are too severe; If an LSE's GCIR is 5 MW when the initial request was submitted and it later rose to 7 MW (40% change), the LSE would be subject to penalty based on SEVERE VSL. Severity should reflect magnitudes of MW values that have a meaningful impact on reliability, not arbitrarily defined calculations.
- 3. The requirements and measure should be changed so that it more accurately reflects the VSLs and should require updating the CBM request if GCIR changes by more than xx MW.
- 4. The only required timing update should be annual updates in order to provide requirements for the new 10th year.
- MOD-004-1 Requirements:
- R3. A Load-Serving Entity (or group of Load-Serving Entities with an aggregated need for CBM) that wants Transfer Capability to be set aside in the form of CBM shall:
- R6. Within five days of the determination of CBM as described in R4 or R5, the Transmission Service Provider shall provide each Load-Serving Entity (or group of Load-Serving Entities with an aggregated need for CBM) that requested CBM and the Balancing Authority hosting its (their) load with a report that includes: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- R6.1. The total amount of CBM for each Posted Path or Flowgate on the Transmission Service Provider's system in each of the months or years specified in the original request. If less than the sum of all requests was established as the CBM for any period:
- - For each Posted Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the months and years specified in the original request
- - The option to request a system impact study.
- Duke Comments:
- 1. How shall penalties be assessed for a group of Load-Serving Entities? Is each LSE subject to the full penalty or is the penalty allocated to each LSE in the group? If allocated, how is that done? Are there NERC rules to addres this situation?
- 2. We forsee difficulties in groups of LSEs making a request for a system impact study and think this option should be removed. CBM is a margin and not a tranmission service

as defined by FERC, so there is no clearly defined mechanism for charging customers for such upgrades. The introduction of this option creates significant controversy which may delay approval of the standard.

- Typo in R2 – Replace CBID with CBMID

- R2. The Transmission Service Provider shall make available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator within seven days of a change.

- MOD-004-1 Requirements: Evaluation deadlines do not consider other received requests

- R4. Within fourteen calendar days of receiving a request or change to a request for CBM that meets the requirements defined in R3.1, the Transmission Service Provider shall set the CBM for the months requested…

- R5. Within sixty calendar days of receiving a request or change to a request for CBM that meets the requirements defined in R3.1, the Transmission Planner shall set the CBM for the years requested…

- R4 High VSL: The Transmission Service Provider set CBM for the months requested as described in R3.1.1.2 more than 14, but not more than 30, days after receiving a request for CBM.

- R4 Severe VSL: The Transmission Service Provider set CBM for the months requested as described in R3.1.1.2 more than 30 days after receiving a request for CBM.

- R5 High VSL: The Transmission Planner set CBM for the years requested as described in R3.1.1.3 more than 60, but not more than 120, days after receiving a request for CBM.

- R5 Severe VSL: The Transmission Planner set CBM for the years requested as described in R3.1.1.3 more than 120 days after receiving a request for CBM.

- Duke Comments:

- CBM requests should be evaluated in queue order along with other Firm service requests and all rules that apply to evaluation timing of firm service request should apply to CBM requests. Monthly CBM requests should be have the same timing requirements as Monthly Firm Point-to-Point requests and Yearly CBM requests should have the same timing requirements as Yearly Firm Point-to-Point requests. Delays in processing CBM requests may legitimately be due to the need to fully process earlier queued requests but the NERC process does not make provisions for such delays. NAESB should revise these rules. Transmission Providers should not be subject to penalties for failure to evaluate on time by both NERC and NAESB rules.

- Modifying CBM after evaluations have been completed is not aligned with current request evaluation process and may cause billing issues

- MOD-004-1 Requirements:

- R4.3. If the sum of all CBM requests can not be met simultaneously, and during the evaluation of monthly ATC or AFC, additional capacity becomes available, increase the CBM based on availability up to a maximum of the sum of all CBM requests.

- R5.3. If the sum of all requests can not be met simultaneously, and during the planning process, additional capacity becomes available, increase the CBM based on availability up to a maximum of the sum of all requests.

- R4 High VSL: The Transmission Service Provider did not follow the process described in R4.1, R4.2, and R4.3.

- R4 Severe VSL: The Transmission Service Provider did not follow the process described in R4.1, R4.2, and R4.3, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met.

- R5 High VSL: The Transmission Planner did not follow the process described in R5.1, R5.2, R5.3, and R5.4.

- R5 Severe VSL: The Transmission Planner did not follow the process described in R5.1, R5.2, R5.3, and R5.4, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met.

- Duke Comments:

- 1. The current request evaluation process concludes with granting of capacity. If additional capacity becomes available, all parties with an interest in that capacity are permitted to request it and it is made available in queue order under established rules. These rules circumvent the current evaluation process and grant higher priority to unfulfilled CBM requests.

- 2. Once an LSE has been denied CBM, the LSE should make other arrangements to meet needs. For example, the LSE could request CBM on a different Posted Path. If other arrangements are made, the LSE no longer needs CBM on the requested path, even if capacity becomes available at a later time.

- 3. If these rules were applied and CBM changed after a rate filings had been submitted by the Transmission Provider (as required in FERC Order 890 paragraphs 257 & 258), the Transmission Provider's filing will be inaccurate.

  4. Duke recommends removing these requirements. If additonal ATC becomes available, LSEs should submit revised requests for CBM capacity.

  - MOD-008-1, Requirements R3 and R4 should allow the Transmission Operator and Transmission Service Provider 14 days instead of 7 days to make the information available after a request, since the responsible individual could be on vacation. The 7 day requirement could be especially burdensome on small entities.

  - MOD-028-1, This proposed change, and the corresponding change proposed below for MOD-030-1 (new R3.2) should both be made for consistency. The technical reason for the change is as follows: Each of the two methods needs to use a model large enough in scope to correctly evaluate TTC. The wording regarding equivalent representation of areas also needs to be refined. The base model that is used is already an equivalent model and the standard is allowing for further reduction of the model at greater distances from the region under study. The wording implies that the base model cannot have any reduction for the RC area under study – it should allow for some reduction in the RC area under study and further reduction for the adjacent RC areas and complete elimination for 2nd tier RC areas. To make this proposed change, delete R2.2 and reword R2.1 as follows: Modeling data and topology of its Reliability Coordinator's area of responsibility and immediately adjacent synchronously connected Reliability Coordination areas.

- MOD-028-1, R3.1 Delete the word "intra-peak"

- MOD-028-1, Add new R6.3 to read as follows: Upon the occurrence of a significant contingency such as the loss of 500 MW generation at any location, or loss of any transformer with low side rated greater than 200 kV, or loss of any other transmission facility rated 500 kV or above.

- MOD-030-1, Delete R3.2, R3.3, R3.4, R3.5 and R3.6 and add new R3.2 to read as follows: Contains modeling data and topology of its Reliability Coordinator's area of responsibility and immediately adjacent synchronously connected Reliability Coordination areas.

- MOD-030-1, Add new R3.3 as follows: Updated as defined below, unless otherwise requested by the Transmission Service Provider: R3.3.1 Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30. R3.3.2 Updated at least once per month for AFC calculations for months two through 13. R3.3.3 Updated upon the occurrence of a significant contingency such as the loss of 500MW generation at any location, or loss of any transformer with low side rated greater than 200 kV, or loss of any other transmission facility rated 500 kV or above.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:
- MOD-001-1, M8 should say "recalculated" rather than "updated".
- MOD-001-1, VSLs for R10 should increase based upon increasing the time allowed to 30 days for making data available under R10 (see comment 3 above). Suggest Moderate VSL of 30 - 45 days, High VSL of 47 - 75 days, and Severe VSL of more than 75 days.
-

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☒ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments: As proposed, MOD-004-1 would require monthly updates of CBM requests, and monthly reallocation of CBM upon changes that affect the amount of CBM available. Paragraphs 257 and 258 from FERC Order No. 890 require that CBM set-aside be

reflected in rates for point-to-point transmission service, such that point-to-point customers do not subsidize CBM for other customers. CBM values will have to be "locked down" to develop and make the rate filing, which FERC may take 60 days to approve. This defines a timing issue which suggests that CBM updates be made significantly less frequently than monthly, perhaps annually. Also, R6.1 includes a provision to request a system impact/facilities study, which suggests customers could pay for upgrades to create CBM. However CBM is a margin and not a tranmission service as defined by FERC, so there is no clearly defined mechanism for charging customers for such upgrades. Detailed observations and comments on MOD-004-1 are as follows:
Observations:

1. CBM requests should be evaluated in queue order, along with other OASIS requests for service and should be evaluated comparable with other firm requests (NAESB is developing these business practices).
2. In order to manage Rate filings to accommodate Order 890 paragraphs 257 and 263, CBM values must, at some point, be "locked in" prior to the filing.
3. Rates should not take effect until FERC approval is received, and at least 60 days should be set aside for the FERC to grant approval.
4. Rates should not change within a month (i.e., rates should be applied to all PTP reservations in full month intervals).
5. The tariff defines procedures for studies of firm point-to-point requests (Section 19) and of network integration transmission service requests (Section 32). These procedures are aligned with respect to response and study times, which are outlined below:
a. After receiving request for service, TSP has 30 days to tender a System Impact Study (SIS) agreement
b. Customer has 15 days execute SIS agreement and return it
c. TP has 60 days to complete SIS or, if unable, TSP must contact customer and provide estimated completion date and reason for delay
d. If all or part of the service can be accommodated, customer has 15 days to execute service agreement or request that it be filed unexecuted
e. If additional upgrades are needed, TSP has 30 days to tender a Facilities Study (FS) agreement
f. Customer has 15 days to execute and return the FS agreement
g. TP has 60 days to complete FS or, if unable, TSP must contact customer and provide estimated completion date and reason for delay
h. Customer provides letter of credit or other security equivalent to the cost of the new facilities or upgrades
i. Customer has 30 days to execute a service agreement or request that it be filed unexecuted
6. The procedure outlined in #5 is for transmission service, but CBM is a margin and not a transmission service. FERC has not provided a mechanism in the pro-forma tariff to charge customers for CBM and, also, FERC did not establish CBM as a separate service in Order 890. As such, there is no clearly defined mechanism for charging customers for transmission system upgrades specifically set aside for CBM.

7. MOD-004-1 establishes 14 days for setting CBM associated with monthly requests (R4.) and 60 days for setting CBM yearly requests (R5.). Requirement R6. establishes a procedure for requesting a system impact study after CBM has been established under Requirements R4. and R5.
8. It is impossible to apply the evaluation timing rules for both R4. and R5. whenever a single modification changes both monthly and yearly values (e.g., LSE submits an

update that requests increase of the monthly value 3 months from now and also requests increase of the yearly values for all subsequent years).

9. TPs must make rate filings to accommodate Order 890 paragraphs 257 and 263, CBM values must, at some point, be "locked in" prior to the filing.
10. Rates should not take effect until FERC approval is received, and at least 60 days should be set aside for the FERC to grant approval.
11. Rates should not change within a month (i.e., rates should be applied to all PTP reservations in full month intervals).

Recommendations:
The following changes are requested so that Transmission Service Providers may meet Order 890 requirement for filing Point-to-Point rates that do not include the cost of the CBM set-aside:

1. Monthly requests should be submitted for the current year and the following two years. (NERC)

a. This should constitute one request type which is only permitted to use available transmission capability (no upgrades). (NERC)
b. Evaluation shall be performed commensurate with reservation response timing rules for monthly firm Point-to-Point requests (NAESB)
c. During the evaluation of Monthly CBM requests, CBM requests should be assigned the same reservation priority as yearly firm PTP and designated network service. (NAESB) This will assure that these requests will be evaluated in queue order and will not be superseded by higher priority requests.
d. The TSP shall establish in its CBMID rules for queuing of monthly CBM requests in order to accommodate the TP's tariff filing needs (each TSP shall establish when Monthly CBM requests are no longer permitted to change). (NERC)

2. Yearly requests should be submitted for the remaining years of the 10 year period.(NERC)

a. This constitutes a second request type which is only permitted to use available transmission capability (no upgrades).(NERC)
b. Yearly requests shall be updated at least yearly, but may be submitted more frequently. (NERC)
c. During the evaluation of Yearly CBM requests, CBM requests should be assigned the same reservation priority as yearly firm PTP and designated network service. (NAESB) This will assure that these requests will be evaluated in queue order and will not be superseded by higher priority requests.
d. Evaluation shall be performed commensurate with reservation response timing rules for yearly firm Point-to-Point requests (NAESB)
e. The TSP shall establish in its CBMID any rules for queuing of yearly CBM requests in order to accommodate the TP's tariff filing needs (each TSP shall establish when Yearly CBM requests are no longer permitted to change). (NERC)

3. At no time shall the Monthly requests overlap the yearly requests. If overlap does occur, the monthly request shall take precedence over the overlapping yearly request. (NERC)
4. NERC should remove the last bullet in R6.1 (The option to request a system impact study.). This will streamline the evaluation process and simplify the Standards approval process (and subsequent FERC proceeding). NERC will not be forced to 1) develop a procedure similar to #5 in Duke Observations (above) or 2) defend why the proposed procedure is different.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Jack Cashin/Barry Green | | |
| Organization: EPSA | | |
| Telephone: 202-628-8200/647-426-3410 | | |
| E-mail: jcashin@epsa.org/bgreenconsulting@rogers.com | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☒ | 5 — Electric Generators |
| ☐ **SERC** | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☒ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments: The implementation plan for the standard is too long. EPSA has not objected to NERC's recent request to FERC to extend by several months, the date when these standards will be submitted to FERC given the amount of work involved in developing these standards. However, to require up to 15 months beyond the date of regulatory approval for implementation of this standard is excessive.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: EPSA would like to provide the following additional comments:

1. MOD 001-1, R3.1 (similar language is used elsewhere) provides that information will be provided "in such detail that, given the same information used by the Transmission

Service Provider, the results of the ATC calculations may be validated." However it is also noted on page 4 of this document above, that all posting requirements will be as determined in the associated NAESB standards. While we are aware of the coordination with NAESB that is on-going and we are actively participating in it, EPSA's assessment of the appropriateness of this requirement can not be completed without knowing the outcome of the related NAESB standard drafting work that is on-going.

2. MOD 004-1, the CBM standard incorporates a number of principles with respect to allocation of CBM, both at the time of ATC calculation and at the time of scheduling deliveries, which EPSA summarizes as follows. CBM, by virtue of being determined as a "set-aside" has priority over all purchases of transmission service, even firm service. This extends into future time frames in that R4.3 states that, if there is initially insufficient CBM to meet all requests, any new interface capability coming available would be allocated first to unfilled CBM requests. Furthermore, when scheduling CBM, LSE's are entitled to utilize any available CBM, not just the quantity that they have requested.

EPSA accepts the notion of a set aside for CBM, contingent on acceptance of some additional principles.

CBM should be purchased by eligible LSEs at full embedded cost of the transmission. This is clearly a superior service that is being provided-it should not be available at a reduced cost.

In the event of an emergency at level EEA2 or higher, LSEs are granted access to all CBM reserved, even if reserved by other LSEs. EPSA acknowledges that under such emergency conditions, all possible accommodations should be made. However, this accommodation together with the charge for service as discussed above, provides considerable incentive to under-reserve CBM. As LSEs are required (R3.2) to update their CBM requirements at least every 31 days, scheduling beyond their reserved amount at the time of an emergency should be investigated, after the fact, for possible violation of this requirement.

R4.3 notes that CBM is made available as a set-aside, such that LSE's are granted priority access to available service, including service that becomes available in future if not all requests can be accommodated initially. Such priority access to future quantities should not receive priority over duly granted roll-over rights.

3. MOD 001-R4 and R5 define the default values for counterflows to be used in the calculations of firm and non-firm ATC. As stated, these values are extremely conservative. R4 and R5 should require an explanation, based on modelling or based on historical values, of whatever values of counterflows are adopted by the TSP.

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Narinder K Saini | |
| Organization: | Entergy Services Inc. | |
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| E-mail: | nsaini@entergy.com | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** Entergy Services Inc. - Transmission

**Lead Contact:** Narinder K. Saini

**Contact Organization:** Entergy Services Inc. - Transmission

**Contact Segment:** Transmission Operator

**Contact Telephone:** 870-543-5420

**Contact E-mail:** nsaini@entergy.com

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Joachim Francis | Entergy Services Inc. | SERC | Transmission Operator |
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>
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>
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>
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>
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- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

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## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

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**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

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- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: Definition of AFC in MOD-030-1 should be expanded to include CBM and TRM in addition to only committed uses similar to that for ATC in NERC standards.

MOD-028-1 R11 and R12 and MOD-030 R8 and R9 include a capitalized term Business Practices in Postback definition. The term Business Practices should either be defined, or clarified in the standard.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement: MOD-001-R2.3 Monthly ATC time period is defined as lasting through month 12. This is not consistent with MOD-030-R3.3 which specifies monthly AFC calculations through month 13. Similar descriptions are included in MOD-028-1 and MOD-029-1. Add in parenthesis "(months 2 through 13)" at the end of this sentence for clarification.

MOD-001-1 R3.1 - replace "may' with "can" in 4th row of this requirement.

MOD-001-1 R3.6 - It is not clear what is expected under Allocation methodology and what needs to be allocated. This requirement should be deleted or Allocation methodology should be more clearly defined.

MOD-001-1 R5 along with R3.2 appears to be "fill in the blank standard" such that the TSP can use any counterflow percentage if they describe how they are accounting for counterflows in R3.2, then R5 is not applicable as it allows them to use their stated method. Therefore, either R5 should be strengthened to make it clear how counterflows and counter-schedules are to be accounted for, or TSP should be allowed to use their method of accounting for couterflows that is included in their ATCID per R3.2.

MOD-001-1 R6 - Minimum time of notification before implementing changes in ATCID should be included in this requirement. In addition, notification via electronic mail in parenthesis appears to be the only medium allowed which may not be reliable. Reference to electronic mail should either be removed or other mediums allowed for notification.

MOD-001-1 R9.3 - Minimum frequency to update monthly ATC should be once a month rather than once a week.

MOD-001-1 R10.12 - This requirement should be deleted as counterflows is not the data to be shared, these are percentage of reservations that are to be used for ATC calculations in a direction opposite to that of reservation that result in increase of the ATC/AFC values.

MOD-004-1 Effective Date should included "(MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1)" between the words six and standards similar to other standards.

MOD-004-1 R1.3 - Words "request the" should be removed as there is no request for schedule, procedure for scheduling of energy is enough.

MOD-004-1 R2 - The Transmission Service Provider needs to make the CBMID available only to the TOs, TSPs, RCs, TPs, and PCs that are in the TSP area or that are adjacent to its network and not to all TOs, TSPs, RCs, TPs, and PCs.

MOD-004-1 R3.1 - CBM is on a Posted Path basis or Flowgate basis whereas GCIR is on an entity basis, therefore either LSE should submit CBM on Posted Path basis or Flowgate basis (LSEs are not expected to know the impact on Posted Paths, or Flowgates of their GCIR, therefore they should preferably just request GCIR and leave calculation of CBM impact to TSP to be determined based on their CBMID under R1.2) which should be included in R3.1, or they can submit GCIR with additional information required in R3.1.1 and TSP shall allocate CBM on Posted Paths or Flowgates based on their CBMID. These requirements need to be made "either Posted Path or Flowgate basis or GCIR" rather than R3.1.1 as additional information required for submitting CBM request.

MOD-004-1 R3.1.2 through R3.1.4 should be deleted or reworded as TSP is not a monitoring entity and they do not have any use for this information. LSE should have this information available for monitoring for compliance. Therfore, these requirements should be reworded accordingly.

MOD-004-1 R3.2 "every thirty-one days" should be changed to "once a month". MOD-004-1 R3.3 - Add "studies conducted in accordance with" between the words "and" and "verifiable".

MOD-004-1 R4.1.1 implies that LSE is going to request GCIR on each path which is not realistic for all methods. Since TSPs are required to allocate GCIR on each Posted Path based on their procedure included in CBMID, it should be reflected in this requirement.

MOD-004-1 R4.1.2 should be modified to be made similar to R4.1.1 such that entities using Flowgate methodology will allocate GCIR on Flowgates based on R1.2 in their CBMID. A cut off limit of 3% or greater for Distribution Factor is not substantiated and should not be included in the standard. TSPs may be required to include their cut off limit it in their CBMID.

MOD-004-1 R4.2.1 second bullet and R4.2.2 second bullet - since ATC is calculated after deducting the CBM, TRM and Existing Transmission Commitments from TTC, it is unclear which ATC has to be used as limit for allocating CBM.

MOD-004-1 R 6.1 - This requirement should be split in two separate sub requirements, the first finishing after the first sentence, and the second sub requirement starts with "If…" and bullets should be made further sub requirements under this new sub requirement as these are applicable only to the situation "If less than the sum of all requests was established as the CBM for any period." System Impact Study is not a viable option, this should be changed to Facility Study.

MOD-004-1 R7 - "within seven calendar days of their making a request" should also be applicable to sub requirements R7.1, since there is no requirements for Transmission Operators to do anything with this data. They can request the data if they need it.

MOD-004-1 R8 - There should be a limit for LSEs to be allowed to schedule only upto the limit of CBM set aside for them as FERC is requiring LSEs to pay for the CBM, if LSEs have not paid for the CBM, they should not be allowed to schedule against the CBM that has been set aside for others. If LSEs do not request enough GCIR and are later allowed to schedule it can adversely impact the reliability of the system.

MOD-004-1 R10 - This should be modified to limit the schedule up to the limit of the LSE's CBM reservation or impact of their GCIR on the CBM on the Posted Path or Flowgate. Setting aside CBM is like reserving the Firm Transmission Service, therefore an entity not reserving enough CBM to start with will impact the reliability of the system by overselling the Firm Transmission Service to others.

MOD-008-1 R1.1 - It may not be possible to identify the impact of each of the uncertainties on each of its respective Posted Paths or Flowgates as included in this requirement. It should be sufficient to include method of coming up with TRM values in terms of percentage or MW taking into account the uncertainties included in this requirement. The language in this requirement should be reworded accordingly.

MOD-008-1 R2 - The first phrase covers the intent to only use the components of uncertainty from R1.1, the second phrase "and shall not include any of the components of Capacity Benefit Margin (CBM)" is redundant and should be deleted.

MOD-008-1 R4 - Parenthesis around the parenthetical statement "within seven days….." should be removed.

MOD-008-1 R5 - There is no justification for the 13 months frequency, it should be changed to once a year or 12 months to be more consistent with business cycles.

MOD-028-1 R1.1 - Word "may" should be replaced by the word "can" in last line.

MOD-028-1 R3 and R4- Insert a word "of" between "all" and "the" in third line.

MOD-028-1 R3.1 and 3.2 - Subrequirements R3.1.1 through R3.1.3 are similar to the sub requirements R3.2.1 through R3.2.3 except using the Load Forecast for corresponding period. The only difference between R3.1 and R3.2 is that one is for the on-peak and the second is for the off-peak with very similar subrequirements. These requirements should be combined into one requirement to simplify the standard and to be specific. Similar approach should be used for R4 to be merged into one requirement with R3 as the only difference is the period of calculation and to use corresponding Load forecasts.

MOD-028-1 R5.3 - Sub requirements for using the sources and sinks included as bullets should be converted into numbered sub requirements.

MOD-028-1 R6.1 - Since forced outages during the week can impact Hourly and Daily TTCs, frequency of TTC calculations for hourly and Daily ATC calculations should be once a day rather than once a week.

MOD-028-1 R7 - It appears there is no consideration of contingencies in this process. Was this the intent of the SDT? If not, the incremental Transfer Capability should be changed to First Contingency Incremental Transfer Capability or impact of contingencies should be included in the language of the requirement.

MOD-028-1 R8 and R6.1 - If Transmission Operator calculates TTC once a week and provide those values to TSP within seven days of calculations, TTC used for Daily and hourly ATC calculations can be as old as 2 weeks, which is unrealistic. The time allowed to transfer TTC values from TO to TSP should be within one day of determination at the maximum, unless otherwise agreed to by the TSP.

MOD-028-1 R9 and R10 - Is Native Load included in NITS? If so, it should be included in the definition, otherwise, another term for Native Load should be included for ETC equation similar to that included in MOD-029-1 R5.

MOD-028-1 R11 and R12 - Postbacks in these requirements refer to as defined in Business Practices, are these NAESB Business Practices or TSP Business Practices? It should be clarified.

MOD-028-1 R12 - Unscheduled Firm reservation need to be offered as non firm, if schedules are not received upto the scheduling deadline. Are these included in the postback definition? If not, these should be included in the equation for non firm ATC calculations.

MOD-029-1 R1.10 - "Extra High Voltage (EHV)" should be defined.

MOD-029-1 R1.12 - "ACTID" is spelled incorrectly, it should be changed to "ATCID".

MOD-029-1 R2.7 - Regional Entity is indicated to have taken action to have the path rated using a different method. There is no requirement in NERC standards for Regional Entity to take action to rate the path, it should be clarified, or reference deleted.

MOD-029-1 R5 and R6 - Definitions of Native Load and NITS include "losses not otherwise included in TRM and CBM standards". There are no such provision to separately include losses in TRM or CBM calculations in current versions of MOD-004-1 and MOD-008-1. The difference should be reconciled or reference removed from this requirement.

MOD-029-1 R6 - There is no term for Native Load in this equation similar to that in R5. Is Native Load never served by a non-firm capacity reservation? If it can be served, the Native Load term should be included in R6 for consistency.

MOD-029-1 R7 and R8 - Postbacks use the term business practices with lower case in this standard. Which business practices this term refers to in this standard? Is it referring to the NAESB Business Practice Standards or TSP Business Practices? It should be clarified. If it means the same as in MOD-028-1 R11 and R12, it should be reconciled by capitalizing it and defining it.

MOD-030-1 R2.2 - Change "once per calendar quarter" to "once per calendar year" for the frequency of updating the list of Flowgates.

MOD-030-1 R3.4, R3.5, and R3.6 - The term "topology" should be replaced with "system topology" to reconcile it with the terms used in other NERC standards.

- MOD-030-1 R5.1 - Reword this requirement to allow the TSP to apply the outage rules defined in the TSP's ATCID and to include third party outage information "where available". It should read: "Include all expected generation and Transmission outages, additions, and retirements as modeled according to the Transmission Service Provider's outage rules defined in the ATCID during the period calculated for the Transmission Service Provider's area, and where available, for all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed".

- MOD-030-1 R5.2 - Reword this requirement to make it consistent with R2.1.3.1 by adding a statement on the threshold limit as follows: "For external (third-party) Flowgates with at least a 5% TDF, use any AFC for each specific Flowgate provided by that third party as the AFC for that flowgate."

MOD-030-1 R6.1.4.2 - Reword to use TSP's rules defined in the ATCID as follows: "Unit commitment and dispatch order, to include all designated network resources and other resources that are commiteted or have the legal obligation to run, as they are expected to run as defined by the Transmission Service Provider's ATCID."

MOD-030-1 R6.3 and 6.4, R7.2 and R7.3 - Threshold of 3% is specified in the requirement with a foot note that TSPs may use a lower than 3% threshold, if desired. The threshold appears to be at the discretion of the TSP, therefore, it should be stated clearly as such. TSPs may be required to disclose it and include it in their ATCID for transparency purposes.

MOD-030-1 R8 - The capitalized term Business Practices used in Postback seems to refer to some defined Business Practices like NAESB or TSP business practices. Either the term should be defined under definitions, or it should be clarified in the requirement. Also, this term is not capitalized in R9, does it mean it is different business practices. The difference should be reconciled.

MOD-030-1 R10 - To make this standard consistent with MOD-028-1 and MOD-029-1, there is no need to include an algorithm in this standard. In addition parenthetical "(and TFC to TTC)" should be deleted. The requirement can read "Transmission Service Providere shall convert or provide a tool to convert Flowgate AFCs to TTCs for Posted Paths by using appropriate distribution factors." and delete the remaining language from this requirement. In case this proposed change is not implemented by the SDT, Entergy proposes that the terms used in this requirement like OTDF Flowgate and PTDF Flowgate should either be defined or clarified.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element: MOD-001-1 M5 - copies of dated electronic email for notification does not ensure that the email has been received by the receiving party. Other mediums should be included or receipt of the email notification should be required as a measure.
MOD-001-1 M6 - Reference to "such as demonstration" is unclear as to what is included in "demonstration" so parenthentical reference should be deleted.
MOD-001-1 M9 - Extra "the" from line 2 between the words "show" and "its" should be deleted.
MOD-004-1 M3 - The measure should also include group of LSEs with aggregated need for CBM as provided in R3.
MOD-004-1 First bullet under Data Retention should refer to CBMID rather than ATCID.
MOD-004-1 Violation Risk Factors - Correct typos in row for R2 "CBID" to be changed to "CBMID".
MOD-008-1 M2 - In case SDT removes reference to CBM as Entergy suggested above, SDT should remove reference to CBMID in this measure also.
MOD-080-1 M5 - In case SDT changes frequency or TRM calculation to 12 months as Entergy suggested above, SDT should make corresponding change in M5.
MOD-028-1 M9 - Correct typo in line 3 from "its" to "it".
MOD-029-1 M2 - Correct typo in line 3 from "ACTID" to "ATCID".
MOD-030-1 Violation Risk Factors - Correct typo in cells under Lower VSL, Moderate, and High VSL for R2 to change from "is" to "it" in last paragraph.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: SDT has done a great job!!!

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| Individual Commenter Information (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: H. Steven Myers | | |
| Organization: ERCOT | | |
| Telephone: 512-248-3077 | | |
| E-mail: smyers@ercot.com | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment (check all industry segments in which your company is registered)** |
| ☒ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
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| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☐ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

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☐ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: For the entire ERCOT Interconnection, the market rules that govern establish, under Texas State Law, that the transmission system is to be operated in an open access process, much as a common carrier. As such, there is not a Transmission Service Market in the ERCOT Interconnection. Therefore, ATC, TTC, CBM, and TRM are not applicable within ERCOT operations. These Standards should have provisions that make it clear that these requirements apply only within market structures in which they are pertinent.

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
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| Name: | Doug Hohlbaugh |
| Organization: | FirstEnergy Corp. |
| Telephone: | (330) 384-4698 |
| E-mail: | hohlbaughdg@firstenergycorp.com |

| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment (check all industry segments in which your company is registered)** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:** Doug Hohlbaugh

**Contact Organization:** FirstEnergy Corp.

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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| Jon Loresch | FE | | |
| Dan Huffman | FE | | |
| Dave Huff | FE | | |
| Dave Folk | FE | | |
| Rob Martinko | FE | | |
| Larry Hartley | FE | | |
| Chris Constantine | FE | | |
| Sam Ciccone | FE | | |
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- Update CBM
- Share CBM data and information
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- Share TRM data and information

### Choose One or More Methodologies

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**Area Interchange Methodology**

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- Modeling requirements
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    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

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**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☒ Yes

☐ No

If "Yes," please identify your concerns. Comments:

1. While we agree that the proposed Implementation Plan allows for sufficient time to achieve compliance with the various requirements, a successful implementation is reliant on tasks that must be completed in succession by NERC Responsible Entities who are not within the same organization. We encourage the standards drafting team to consider setting midpoint milestone dates, where appropriate, to allow sufficient time for entities that have tasks that are dependent upon the timely completion of other work prior to their own. Requirements for "implementation documentation" would be effective after 12 months, but then other data that relies on these documents should have additional time for implementation.

2. The Implementation Plan shows a table of the applicable entities for each proposed standard. In this table, the Purchasing-Selling Entity (PSE) is shown as applicable to MOD-008, but it is not listed as an applicable entity within the text of this standard or any of the proposed standards.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

MOD-004-1 - GCIR Definition: This definition may incorrectly imply that this is merely another resource that an LSE can use to meet its Resource Adequacy Requirements (RAR). RAR, such as planning reserve requirements (PRM), cannot be met with the use of CBM. Also, the definition refers to GCIR as "an alternative to internal resources" which may be misleading. The definition needs to address the fact that GCIR (as CBM) can only be used in an emergency. It is a "contingency option" rather than a "resource alternative".

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

1. MOD-001-1:

- Applicability - Should include the Reliability Coordinator (RC). Per the NERC functional model, the RC is responsible for the "coordination of ATC with Transmission Service Providers".

- R1 - The Transmission Operator (TOP) should not be responsible for choosing an ATC methodology; any methodology should be coordinated with the TOP, but the ultimate responsibility should fall onto the TSP. Also, it should be made clear that the use of the three methodologies must be in accordance with the "MOD" standards. Therefore, we propose a rewording of R1 as follows: "The Transmission Service Provider, in coordination with the Reliability Coordinator and Transmission Operator, shall choose an ATC methodology [footnote 1] (Area Interchange methodology, Rated System Path methodology, or Flowgate methodology in accordance with MOD-028, MOD-029, and MOD-030, respectively) for each Posted Path per time period for use in determining Transfer Capabilities of those Facilities within its Planning Coordinator's planning area".

- R8 should not include the Transmission Operator. The TOP is not responsible for calculating the ATC, TTC, or AFC.

2. MOD-004-1:

- R3 - This requirement should either be eliminated or specified under R1, as applicable to TSPs. Where R1 requires the TSP to have a procedure for LSEs to request CBM, R3 prescribes part of that procedure. If R1 is intended to give TSPs full liberty to develop its CBM procedure, then R3 is an unnecessary requirement. If instead R3 is an element of the procedure that must be common to all, then it should be added as a requirement for TSPs to include in their procedures.

- R8 - This requirement should be included in a NAESB business standard. Any aspects of R8 as applicable to TSPs should remain.

- Effective Date: For consistency, the Effective Date section should be replaced to match what is in the other proposed standards under the Proposed Effective Date which references the other standards and is more complete that what is shown in MOD-004.

3. MOD-008-1:

- Applicability - Since TRM is a network-wide margin critical to calculating ATC, the TRM standard should also be applicable to the Reliability Coordinator (RC). Per the NERC functional model, the RC is responsible for the "coordination of ATC with Transmission Service Providers". Lastly, the RC must be included as an applicable entity as directed by FERC Order 693, Par. 1126.

- R1 - Since the Transmission Service Provider (TSP) is ultimately responsible for calculating and assuring proper ATC for its footprint, and since, per MOD-004-1 R1, the TSP is responsible for maintaining a CBMID, then it should follow that the TSP, and not the Transmission Operator (TOP), should be responsible for maintaining a TRMID. Plus, in R4 of MOD-008-1, the TSP has to make the TRMID available to other TSPs when requested. Wouldn't the process be smoother and more reliable if the TSP didn't first have to ask the TOP for the TRMID if the TSP already had and maintained its own

TRMID? Therefore R1 should be reworded as follows: "Each Transmission Service Provider, in coordination with the Transmission Operator and Reliability Coordinator, shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information:"

Then, if R1 is changed as suggested, the following changes to other requirements to MOD-008-1 must be considered:

- R2 & R3 - Replace "Transmission Operator" with "Transmission Service Provider"

- R3.1 - Reword as follows: "The Transmission Operators with Facilities governed by the Transmission Service Provider".

- R4 - Remove "used by its Transmission Operator(s)"

- R5 - "Each Transmission Service Provider shall calculate, at least once every 13 months (in accordance with the definitions in its TRMID), a TRM value for the following time periods (on each Posted Path or Flowgate) and shall provide these TRM values to its Transmission Operator(s) and Transmission Planner(s) within seven calendar days of the calculation:

4. MOD-030-1:

- Applicability - Since Flowgates are points within the Transmission system through which Interchange Distribution Calculations are performed by the Reliability Coordinator, this standard should also be applicable to the Reliability Coordinator (RC). Also, per the NERC functional model, the RC is responsible for the "coordination of ATC with Transmission Service Providers".

- R2 - Although the Transmission Operator assists with gathering this information, this requirement should ultimately be the responsibility of the Transmission Service Provider (TSP), since the TSP prepares and maintains the Available Transfer Capability Implementation Document (ATCID). Also, the Reliability Coordinator should assist in gathering this data since this entity is closely monitoring Flowgate capacities in its area. Therefore, we suggest rewording R2 as follows: "The Transmission Service Provider, in coordination with the Transmission Operator and Reliability Coordinator, shall perform the following:"

- R3 - Incorrectly states that the Transmission Operator (TOP) determines the AFC. R3 should be reworded as follows: "The Transmission Operator, in coordination with the Reliability Coordinator, shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria:”

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

1. MOD-001-1: Measure M2 - Change typographical error at the end of the measure that currently reads "(R1)" to "(R2)".

2. MOD-001-1: Measure M7 should not include the Transmission Operator. The TOP is not responsible for calculating the ATC, TTC, or AFC.

3. MOD-001-1: VSL-Severe for R2 incorrectly includes the Transmission Operator. This requirement is only applicable to the Transmission Service Provider.

4. Per our rewording suggestions in Question 3 and Question 6, several measures and compliance elements must be reviewed and revised by the SDT.

- E.g., MOD-030-1: Measure M7 - Per our rewording suggested in Question 3 for Requirement R3, M7 should be reworded as follows: "The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to support the AFC calculated by the Transmission Service Provider contains the information specified in R3."

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

1. MOD-001-1:

- R2 & R9 - There is no calculation requirement for yearly ATC in R2 or R9. Yet in MOD-004-1, R3.1 requires the identification of a CBM amount for, "each month for each year for the next ten year period."

- R6 - In addition to notification, before implementation of a new ATCID, the Transmission Service Provider should allow for a comment period. This will assure that all the affected entities have been given an opportunity to provide valuable clerical and technical input on the document.

- Counter-flow calculations in the past were difficult to justify and manage. This standard attempts to manage counter-flows by requiring TSPs to specify their accounting method in the ATCID, but does not require any justification of the method used for applying them. This situation could result in inconsistency in ATC calculations and application. Requirements should be developed that govern the calculation and application of counter-flows to ensure consistency and transparency.

2. MOD-004-1:

- The need for LSE involvement in setting CBM levels is completely dependent on the Resource Adequacy Requirement structure, and for some structures it would not be appropriate for LSEs to have input into the CBM calculation. For example, in PJM, an individual LSE (1) may not know if there is enough capacity in the market to meet reliability needs, or even what are the specific resources serving their load; (2) may have no responsibility to identify specific capacity resources beyond the obligation to purchase capacity credits from unspecified sources. Overall capacity management, short-term and long-term reliability responsibility, resides at the ISO level.

- In general, this standard may lead to situations that cause CBM reservations to be excessively higher than needed. There is no reference to a CBM calculation methodology, leaving LSEs free to request CBM on any basis. Many LSEs do not have the necessary tools needed to make proper CBM calculation, which could lead to simplistic and conservatively high CBM requests.

- Further compounding the problem of over-reserving CBM is the provision that calls for the TSP and TP to set the aggregate CBM level as the sum of all LSE requests such that all requests can be met simultaneously. It is unlikely all LSE adverse scenarios will occur. It is even more unlikely that all will occur at the same time. These provisions will result with too much CBM being set aside. Diversity is not taken into account.

- There are no provisions for the TP or TSP to challenge unreasonable CBM requests.

- This standard does not incorporate the resource adequacy criteria into the process of setting the total CBM value. The simple summation of CBM requests ignores the uncertainty associated with the scenarios behind the CBM requests.

- R2 - "CBID" should be "CBMID"

- R3 & R4 - A monthly value is extremely difficult to administrate and implement in the ATC calculation. Such a requirement will incur significant cost and subject the TSP to significant increases in cost. We suggest leaving it to each region to decide on the time intervals.

- R3.1 – This section should be clarified. It states "requested for each month for each year for the next ten year period." Do we really want 120 months worth of requests, or 12 monthly requests and 9 yearly? Also, the ATC postings only cover at most a 12 month period in MOD-001-1. Why is it necessary to have such a disparity in the period of coverage? R3.2 requires updating this CBM request at least every 31 days to reflect any changes that alter future needs. New development projects influence future needs for load growth. The probability that these projects will come to fruition can change from month to month. Is it reasonable to require a ten year look ahead to be revised on a 31 day cycle?

- R3.1.1 - In some areas it may not be possible that CBM can be determined from GCIR at the LSE level, especially if the standard will require data ten years in the future. In retail choice areas, an LSE has few load responsibilities (therefore resource responsibilities) for more than a couple years.

- R3.1.1.1 - CBM will be called upon in an emergency. We are not sure that it is feasible to identify the Balancing Authority or Posted Paths in all areas. We assume CBM would be used to bring in the most appropriate resources at any given time, but can that be known now for an emergency in the future?

- R3.1.2 - The basis for the request of CBM is not clearly defined. This requirement indicates that GCIR must be based on standards, criteria, established by other authorities. The LSE must document the Resource Adequacy Requirement (RAR) standards & authorities that form the basis of their request, and all details of the associated resource studies. This implies that it is a clear, objectively-determined parameter, yet it does not say how any particular elements of the results of the RAR study fit into the GCIR calculation.

- R4.1 either contains an extra colon that should be deleted, or is missing "(TRM"

- R4.3, R5.3, and R6 address the idea that the sum of all requests may be greater than the available capacity on the facility and directs the CBM to be increased based on availability up to the sum of all CBM requests. The standard is silent on what is to be done if the sum of all requests is greater and no additional capacity is made available on the facility. The standard should include the method for allocating the requests in this situation.

- R9 - Should be adjusted so that it explicitly states that only the timing requirements for the Real-Time market only will be waived. For example, the Day-Ahead Market timing requirements cannot be waived.

- R8, R9 & R10 - This standard refers to Interchange Transaction Tags. This has become problematic in that there are no requirements to tag interchange transactions in the NERC Standards posted on 10/23/07 with one exception. INT-004-1 still requires a modification to the tag for dynamic interchange transaction modifications. IRO-006 still relies heavily on interchange transaction tags for the TLR procedures, but without a requirement to tag a transaction, it is not clear how this procedure is accomplished under today’s standards. Until transaction tags are required by the standards, the references in R9 and R10 that rely on interchange transaction tagging should be revised.

3. MOD-008-1:

- R1.3. - Should be revised to state the description of the method used to allocate TRM across Posted Paths or Flowgates. As currently stated, it appears to be a list of Posted Paths or Flowgates with a TRM value or percentage assigned.

- R3 - Should be revised to state within seven calendar days of the receipt of a written request.

- R4 - Should be revised to state within seven calendar days of the receipt of a documented request for such information.

4. MOD-028-1:

- R5.3 - The requirement states, “If the source has not been specified, use the interface point with the adjacent upstream Transmission Service Provider as the source.” It may be difficult to determine the upstream Transmission Service Provider when the source has not been specified. The same is true for “If the sink has not been specified, use the interface point with the adjacent downstream Transmission Service Provider.” These statements should be revised to state, “If the source has not been specified and the sink has, use the interface point with the adjacent Transmission Service Provider upstream from the source as the source.” And “If the sink has not been specified and the source has, use the interface point with the adjacent Transmission Service Provider downstream from the sink as the sink.”

- R11 & R12 - Use the term “postbacks” that is not defined in the NERC Glossary nor is it well defined in this standard. It appears the requirement is communicating that it is defined in Business Practices. We suggest it be defined in the ATCID much like the Counterflows are described in the ATCID.

5. MOD-029-1:

- R7 & R8 - See our comments regarding "Postbacks" above.

6. MOD-030-1:

- R2.1.2 - The phrase "first three limiting" is too prescriptive and should be removed. For example, if the most limiting first contingency transfer is a large value, say 10,000, adding the first three limiting elements/contingency combinations is not necessary. If the requirement cannot be removed, we suggest adding wording that sets a transfer level such that the first three constraints that cause the FCITC to fall under that level will be captured. Also, "source sink combinations" needs to be further defined as a calculation; an entity of any size could have thousands of these possible combinations. Also, if this in-depth study is required, the frequency in R2.2 should be decreased (as this is a minimum standard to maintain the reliability of the BES).

- R4 - The requirement states, "If the source has not been specified, use the interface point with the adjacent upstream Transmission Service Provider as the source." It may be difficult to determine the upstream Transmission Service Provider when the source has not been specified. The same is true for "If the sink has not been specified, use the interface point with the adjacent downstream Transmission Service Provider." These statements should be revised to state, "If the source has not been specified and the sink has, use the interface point with the adjacent Transmission Service Provider upstream from the source as the source." And "If the sink has not been specified and the source has, use the interface point with the adjacent Transmission Service Provider downstream from the sink as the sink."

- R5.2 - It is not clear to us what the definition of a "third-party" is and how it is used in AFC calulcations. Please clarify.

- R8 & R9 - See our comments regarding "Postbacks" above.

- R9 - "Counterflows" is missing subscript "NFi" in the formula.

7. MOD-001-1 (R7, R10), MOD-004-1 (R2), MOD-008-1 (R4), and throughout other standards the drafting team uses the phrase, "make available." In addition, per FERC Order 693 (e.g. Par. 1023), wording should be added as to how it needs to be made available, such as on a website. Furthermore with regard to the sharing of information, requirements in these standards that require an entity provide information to another entity should have a standard method for providing the information or at a minimum require a negotiated method and format for providing the information. This will also require dispute resolution when two entities cannot agree on a method or format.

8. These standards do not address the market operation methods in use today. Currently, the Transmission Service Providers are the RTOs in some markets. These entities are also the market operators and not-for-profit organizations that have no vested financial interest in the amount of TTC assigned to a flow-gate or transmission facility. The modification of these standards to place the burden on the Transmission Operator for these calculations is a significant step backwards that should be revised to avoid the need for waivers or delegation agreements and to meet the needs of the old method of operation and the new market methodology.

9. Several requirements related to ATC have been incorporated into NAESB standards. It would be beneficial for these standards to be more transparent to the industry since it is challenging to find these standards on NAESB's website or some other means. It may help to have a direct link to these business practices on NERC's website in the future. Furthermore, it may help to incorporate these NAESB standards into NERC's standard review process for this and future projects in an effort to achieve full industry input on the development of these practices.

10. This set of ATC standards may need to go through a field test to determine how effective these calculations for ATC can be based on all the new requirements for Implementation Documents and Applicability to Transmission Operators and Load Serving entities that may not have ever dealt with these sorts of calculations in the past. If a field test is not an option due to time constraints, then the effective date should be pushed out another 12 months.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | FRCC |
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| **Contact Organization:** | FRCC |
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| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| W. R. Schoneck | Florida Power & Light Company | FRCC | 3 |
| A. L. Barredo | Florida Power & Light Company | FRCC | 3 |
| D. A. McInnis | Florida Power & Light Company | FRCC | 3 |
| Aaron Staley | Orlando Utilities Commission | FRCC | 3 |
| Earl Fair | Gainesville Regional Utilities | FRCC | 1 |
| Paul Graves | Progress Energy Florida | FRCC | 3 |
| Art Nordlinger | Tampa Electric Company | FRCC | 1 |
| Annie Tra | Seminole Electric Cooperative, Inc. | FRCC | 4 |
| Aaron Staley | Orlando Utilities Commission | FRCC | 1 |
| Phuong Tran | Lakeland Electric | FRCC | 1 |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

### Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

> **MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.
>
> **MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.
>
> **MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.
>
> **MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.
>
> **MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.
>
> **MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

   ☐ Yes

   ☒ No

   If "Yes," please identify your concerns. Comments:

2. If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

   Incorrect Definition: MOD-001-1: What is the "Time Horizon: Operations Planning"?

   R8 specifies "associated operations studies or planning studies for the time period studied". In order to be consistent with Order 890, it should specify "associated operating horizon studies or planning horizon studies for the product time period being calculated" and further, since these horizons are being used in the context of ATC determination, the prefix "ATC" should be added to eliminate ambiguity, just as the TPL standards do with near-term planning horizon (year 1 to year 5) and longer term planning horizon (years 6 to 10)

   MOD-028-1: R5.3 – define "interface point" and "adjacent upstream TSP". This requirement is complex and it should include examples with pictures.

3. If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

   Incorrect Requirement:
   MOD 001: R9: This should be revised to indicate that updates are required only when data has changed. There are many entities whose ATC data may not change on a regular basis and requiring them to repost identical numbers on an hourly basis and maintain a log does not enhance reliability. Proposed wording "Each Transmission Service Provider shall update ATC at a minimum on the following frequency when the value has changed:"

   MOD-004-1: CBM: There does not seem to be a way to not have a CBMID even though the TSP policy is not to reserve CBM on any of its interfaces. Could the applicability be modified to exclude entities that do not use CBM?

   MOD-008-1: TRM: The sub-requirements in R1.4 and R5 describe the ATC Operating, ATC Scheduling, and ATC Planning horizons as specified by FERC in Order 890 and should be identified by name to be consistent with the other MOD standards.

   MOD-028-1: Area Interchange Methodology: R3 appears to require calculating TTCs for Posted Paths for intra-day and next day, on-peak and off-peak, R4 requires calculating

TTCs for time periods beyond next day, and then R6 specifies frequencies that don't correspond. For example, R4.1.2 requires use of peak load forecast for the day being calculated, but R6.1 says calculate TTC for daily only once per week – which day's peak load forecast gets used?

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:
MOD 001: M8 (referencing R9) should be revised to require proof of updates only when the information posted needs to be changed. For Example: "The Transmission Service Provider shall provide evidence (such as logs or data) that it has updated the hourly, daily and monthly ATC's on at least the minimum frequencies specified in R9 when those ATC values have changed.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:
MOD 28 Requirements, Measures and VSL's for R9-R12 are not explicit that setting a value to "Zero" is "using" the value. This could cause confusion on audits. R9-R12 should be revised to indicate that "Zero" is an acceptable value and qualifies as "using" the element. For example under each item where the elements are defined a line could be added stating. "The Transmission Service Provider shall show all elements of the calculation even those that have a value of zero for the path being calculated, and that value of zero for an element is considered using the element."

MOD-001-1: ATC: The frequency of calculation in R9 for the same products in R2 adds little or no accuracy or value to the results, particularly towards the end of the horizon. For example, hourly ATC must be re-calculated for three to seven days out every hour, the same as for two to four hours out. This should be relaxed to a tiered requirement. The postings should be made out to 168 hours, however, the frequency could be relaxed so that the outer bounds of the horizon are updated less frequently. (i.e. R9.1 For next 4 hours, once per hour, for hours beyond 4 hours out until end of next day (midnight), once every 6 hours, for hours beyond end of next day, once per day.)

MOD-001-1: ATC: R10 is exhaustive. The requester should be required to have cause to request such information and be required to pay for the administrative costs of collecting and transmitting the information. Much of the listed information is embedded within the power-flow models, and transmitting models electronically on an hourly basis to potentially multiple requesters would be very costly and time-consuming. If a requester has a grievance or dispute, then the historical data should be sufficient to provide for the calculations in question.

MOD-028-1: Area Interchange Methodology: R7 – In step 'a' the 5% distribution factor should be specified as OTDF or PTDF (should be OTDF).

MOD -028-1: R7 – in Step 'A' the 5% distribution factor appears to only apply to adjacent systems. This could result in a scenario where Utility B prudently limits ATC based on a facility in their system between them and Utility C, however Utility A allows a transaction to C that has the same impact on the same facility because of the 5% rule. We suggest that the ATCID should specify the handling of off system non path impacts.

MOD-028-1: In R7 step 'c', Please further define "all impacts of firm transmission service included in the study model" and/or provide an example. In our region this phrase was interpreted by some to mean "firm point to point only" and by others to include network and native service.

MOD-029-1 R1 This section should specifically say that all the BA-BA transactions are removed from the load flow model. These transactions are accounted for under ETC.

MOD-29-1 R1-6 This section implies that load is in the model which means the TTC calculated would be reduced due to the load. In MOD-29-1 R5 load is again accounted for under ETC. It appears that the equation for ATC in MOD-29-2 R7 double counts the effect of load because it is included in the TTC and in ETC.

Mod-29-1 R5 More detail is needed as to how the components of ETC are to be determined from a load flow model. Particularly, NLF, NITSF and GFF.

MOD-029-1 R7 C: Assuming no other changes this sentence should be revised to state "Determine the impacts of Firm Transmission Service that were included in the study model." The summing of this item with the incremental Transfer Capability occurs in Step D and mentioning it here in C is redundant.

Mod 28 R7c: This term should have a defined variable name or acronym.

Mod 28 R7c, R9, R10, R11, R12: In R7c the "impacting firm transmission service" is determined and summed to the ITC results to get the TTC. In R9 & R10 an ETC is determined then in R11 & R12 that is deducted from the TTC to get ATC. However there is no tie made between the undefined "impacting Firm Transmission Service" R7c and the ETC in R9 & R10. So there is no requirement that would prevent a service from being modeled in the model, not included in the "Impacting Firm Transmission Service" (IFTS) but then included in the ETC calculation, thereby effectively double counting the service. The service was on in the model, thereby reducing the capacity, the service was not added to the model in the IFTS but was deducted from the capacity in the ETC as if it wasn't running in the model.

We suggest that the drafting develop a set of examples to clearly explain the principles and calculations laid out in the standards to help insure uniformity in interpretation of the standards. See that attached example, which while basic, could be modified to emphasize specific concepts like CBM, Postbacks, Counter Flows, TRM, "Impacting Firm Transmission Service", etc.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

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| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

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The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

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**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

# Arrangement of Requirements within the Proposed Set of 'ATC' Standards

## MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

## Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

   ☐ Yes

   ☒ No

   If "Yes," please identify your concerns. Comments: GTC does not think that additional time is needed; however, GTC would like to point out that the implemetation period should not be shortened. The standards require development of extensive NAESB business practice standards. NAESB's working plan requires approximately six months after NERC approval of the NERC standards to create NAESB business practices that implement the NERC standards. Therefore, entities that must implement the NERC standards will only have approximately six months after the NAESB standards to implement the combination of NERC and NAESB standards.

2. If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

   Incorrect Definition: MOD-028, -029 and -030 refer to "Postbacks" with a definition that uses the term "postback". There is not a definition in the NERC Glossary for this term. The current NAESB draft definition (dated 9/12/07) is "The increase in ATC due to a change in status of a Transmission Service request or the release of unscheduled Transmission Service." The following definitions are suggested for MOD-028, -029 and -030:

   "Postbacks(F) are the changes in Firm ATC due to a change in Firm Transmission Service during that period, as defined in Business Practices";

   "Postbacks(NF) are the changes in non-firm ATC due to a change in non-firm Transmission Service, as defined in Business Practices".

3. If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

   Incorrect Requirement: In MOD-008-1, R5, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. An error in calculating TRM does not change the resulting TTC or TFC; therefore an error in calculating TRM cannot be a Medium or Severe Violation Risk Factor.

   In MOD-028-1, R2, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

In MOD-028-1, R3, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

MOD-028-1, R5 uses to the term "interface point" with the adjacent Transmission Service Provider; "interface point" is not defined. To meet MOD-028-1, R5 and MOD-030-1, R4, a Transmission Operator must define and simulate an artificial source or sink at the interface. The requirements should replace each occurrence of the phrase "use the interface point" with the phrase "use the adjacent Transmission Service Provider's area".

MOD-028-1, R8 is missing a Violation Risk Factor and a Time Horizon. They should be Violation Risk Factor: Lower and Time Horizon: Operations Planning.

In MOD-028-1, R9, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

In MOD-028-1, R11, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

In MOD-029-1, R1, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

In MOD-029-1, R2, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

In MOD-029-1, R5, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

In MOD-029-1, R7, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

In MOD-030-1, R2, the Violation Risk Factor is listed as Lower; it should be listed as Medium. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. MOD-030-1, R2 requires that the TFC be less than the SOL; therefore MOD-030-1, R2 should have a Medium Violation Risk Factor.

In MOD-030-1, R3, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

MOD-030-1,R4 uses the term "interface point" with the adjacent Transmission Service Provider; "interface point" is not defined. To meet MOD-028-1, R5 and MOD-030-1, R4, a Transmission Operator must define and simulate an artificial source or sink at the interface. The requirements should replace each occurrence of the phrase "use the interface point" with the phrase "use the adjacent Transmission Service Provider's area".

In MOD-030-1, R5, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

In MOD-030-1, R6, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

In MOD-030-1, R9, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect,

please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element: MOD-001-1, R9, Lower VSL says "For Hourly, not calculated within 5hrs". MOD-001-1, R9, Medium VSL says "For Hourly, not calculated in more than 5 hours but not more than 10 hours". This language appears to allow a TSP to not calculate for 4:59 hours, while not calulating for 5 hours is a Lower VSL and more than 5 hours is a Medium VSL. We suggest that the MOD-001-1, R9, Lower VSL should be re-written to say "For Hourly, not calculated in more than 2 hours but not more than 5 hours".

MOD-028-1, M5 requires Transmission Operators to "provide copies of contracts" without stating the entities that can receive (potentially) commercially sensitive "copies of contracts". MOD-028-1, M5 should state "The Transmission Operator shall make available, only to authorized individuals that have executed a Confidentiality Agreement and that are performing official RRO audit activities, copies of contracts that contain requirements to allocate TTCs to show that any contractual allocations of TTC were respected as required in R5.2. Transmission Operators may redact the copies of the contracts to omit commercially sensitive information."

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If “Yes,” please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: MOD-001-1, R10 requires "within fourteen calendar days" for a TSP to begin supplying large amounts of data used in calculations. "Within thirty calendar days" is more realistic to supply large amounts data that could be extensive and detailed.

MOD-004-1, R2 requires a TSP to act within 7 calendar days, R6 requires a TSP to act within 5 calendar days, R7.1 and R7.2 require a TSP to act within 7 calendar days. R2, R6, R7.1 and R7.2 should be changed to match the 14 calendar days required by R4. 14 calendar days is more appropriate for data requests that are "reports", "supporting data", documentation, work papers, etc.

MOD-008-1 R3 and R4 require "seven calendar days" for a TSP to act. 14 calendar days is more appropriate for data requests that are "underlying documentation, work papers…", etc.

MOD-028-1, R5, it appear that the word "shall" is not needed in the following sentence. "-If the sink has been specified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point shall as the sink."

MOD-028-1, the VSL for R8 is missing a measurement: The Transmission Operator has not provided its Transmission Service Provider with its Posted Path TTCs within ___ (should be seven) calendar days of their determination, but is has not been more than 21 calendar days since their determination.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

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**Lead Contact:**

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| Additional Member Name | Additional Member Organization | Region* | Segment* |
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The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

# Arrangement of Requirements within the Proposed Set of 'ATC' Standards

## MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

## Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

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- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

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- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

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The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: MOD-028-1(Area Interchange Methodology) VSL Requirement 2: The requirement talks about Facility ratings from both Transmission Owners and Generator Owners. The associated VSL description forgot to include Generator Owners. As well, this VSL talks about not using a certain number of Facility Ratings which I assume would result in some TTC error therefore I would propose changing how this requirement is measured:

Lower VSL: 1%<TTC error<5%

Moderate VSL:  5%<TTC error < 8%

High VSL: 8%< TTC error < 10%

Severe VSL: TTC error > 10%

As well this can be used for R3 and likely several other requirements were TTC and ATC errors can result from non-compliance.

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RELIABILITY CORPORATION

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Roger Champagne | |
| Organization: | Hydro-Québec TransÉnergie (HQT) | |
| Telephone: | 514 289-2211, X 2766 | |
| E-mail: | champagne.roger.2@hydro.qc.ca | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☒ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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| Danielle | Beaulieu | **NPCC** | 1 |
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# Arrangement of Requirements within the Proposed Set of 'ATC' Standards

## MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

## Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

MOD-001

- 1. R1: The reference to the Planning Coordinator's planning area in R1 is not appropriate; the reference should be to the Transmission Operator's operating area.

- 2. R3.3: Since this standard deals with short-term Transmission Service, the reference to Planning Coordinator should be removed from R3.3, R6.1 and R6.4

- 3. R3.3: This should be reworded to be clear that the TOP is providing input (TTC or TFC) to the TSP to perform ATC calc. Also suggest removing reference to a 'tariff' since non-jurisdictional entities may not have a tariff. Suggest the following language: The identity of the Transmission Operators that provide data on each Posted Path for use by the Transmission Service Provider in calculating ATC. Acronyms TOP, TFC, and TSP need to be defined in the Background Information on p. 3. The abbreviation "calc." should be spelled out.

- 4. R4 and R5 should reference both the terms counter-schedules and counterflow throughout the requirements

  5. R9 (or at a minimum the Measure for R9) must be modified to be clear that if TSP can demonstrate that no inputs to the ATC calculation have changed that an update of a 'timestamp' on an ATC value is not required. Suggested options for the language in R9: "Each TSP shall update ATC at a minimum on the following frequency, except that if all inputs to ATC are unchanged no update is required:" OR "Each TSP shall update ATC at a minimum on the frequencies listed below. However, if all inputs to ATC are unchanged no update is required."

MOD-029

- 1. R1.10 refers to EHV without it being a defined term and different regions could define EHV to be different voltage levels; suggest one of the following actions be taken: (a) include the desired kV level of the BPS system in the standard, (b) remove the reference to EHV entirely, (c) add a NERC glossary term. EHV should be defined in the Background Information on p.3 and be understood to be applicable to and restricted to the BPS irrespective of that voltage level. That definition must also include the BPS voltage level it refers to.

  2. R2 language could be interpreted that all N-2 contingencies must be considered in a TTC study. If the intent that the TTC study should consider all currently required planning criteria, a general reference should be made to the planning standards rather than try to summarize and reiterate those requirements here.

  3. R2.1.5 contains a very specific consideration for EHV contingencies to be considered in the TTC. Is there a reliability need for ALL regions to consider EHVs in this manner? If not, we suggest removing this requirement from the NERC standard, where it can be added in a more detailed regional standard if required by a particular region. EHV should be defined in the Background Information on p. 3; the definition must include the BPS voltage level it refers to.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:
1. VSL for MOD-028 R2 and R3 are is not clear if the 'errors' that are allowed are for a given TTC study or the allowed cumulative 'errors' since the last audit? (this language should also be clarified on comparable VSLs in MOD-029 and MOD-030). "Are is" in the first sentence needs to be corrected.

2. If suggestions in Question 3 and 6 are accepted, the associated Measures and VSLs will also need to be updated accordingly.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments: We would like confirmation from the Drafting Team that our interpretation of how the MOD-004 requirements can apply in areas that employ competitive wholesale markets in a manner that does not conflict with approved tariffs. In ISO/RTO markets where resource adequacy is performed by the ISO/RTO (i.e., an independent Balancing Authority), and by virtue of the market, the Transmission Service Provider does not offer transmission service in advance of physical flow, there is no ability for the LSE to 'request' CBM as defined in the standards. However, the reliability need for CBM by the LSE is satisfied by the market rules and associated tariffs. As such, the entities' CBMID would describe how the reliability needs of the LSEs, as relates to securing CBM is met and why there is no need for the LSE to 'request' CBM in the manner described in the standards. We would like confirmation from the Drafting Team that documentation of

CBMID in this manner – i.e., through specifying that an LSE need not "request" any particular transmission service – would satisfy the reliability requirements of MOD-004. LSE, and CBMID should be defined in the Background Information on p. 3.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

MOD-001

1.R1: While in many cases, the decision on which ATC methodology to use may be made jointly between the TSP and TOP. However, since you cannot have joint responsibility in the standard, the TOP is the appropriate Functional Model entity. Acronyms TSP, and TOP need to be defined in the Background Information on p. 3.

2.R8: Since this standard deals with short-term Transmission Service, the reference to planning studies should be removed from R8

3. R8 is an appropriate representation of the broad FERC requirement as-written that will force entities to make a conscious effort to ensure this consistency occurs. While the language is somewhat vague, we recognize that adding more detail would be unreasonably difficult. We would suggest that detail be added in the measures to provide examples of what a valid demonstration would be. For example, TOP/TSP may provide evidence to demonstrate that the source of the inputs used in the operational studies is the same as for the TTC/ATC studies. TOP and TSP need to be defined in the Background Information on p. 3.

MOD-028

1. R8 should be broken down into the different timeframes; sending TTC values used in hourly and daily ATC calculations seven days after being calculated is too late. Suggest: 8.1 within one calendar day of its determination for TTCs used in hourly and daily ATC calculations; 8.2 within seven calendar day of its determination for TTCs used in monthly ATC calculations.

MOD-030

1. R4 seems duplicative of MOD-001 R8

2. R6.3, 6.4 - The last sentence of R6.3 seems to belong in 6.4 not 6.3

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Ron Falsetti | | |
| Organization: IESO | | |
| Telephone: 905-855-6187 | | |
| E-mail: ron.falsetti@ieso.ca | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
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**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
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### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
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- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☒ Yes

☐ No

If "Yes," please identify your concerns. Comments: 1) The standards suggest retiring FAC-012 and FAC-013. We are uncomfortable with this since we strongly believe the MOD standards fall short of replacing these requirements and in our view the TTC should be determined within the FAC standards.

2) Tying the implementation date with the various regulatory approvals means that the effective dates will be all over the map. The effective dates should be set to a specific time after NERC BOT approval, that allows time for the appropriate regulatory approvals. These concerns were presented to NERC some time ago and it is our understanding that they had accepted this argument.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

MOD-004

CBM is intended to be used for accessing generation from external sources to meet the LSE's PLANNED capacity installation requirement. The word "planned" should be inserted in the definition for GCIR.

MOD-28 and MOD-029

The definitions for Area interchange Methodology and Rated System Path Methodology seem to be woefully inadequate - the "determination via simulation" explanation for the methodolgies is pretty meaningless by itself - these should either be explained properly or be removed from the standards as "definitions" or could be added to the MOD-001 definition list.

MOD-030

Is the Flowgate Methodology definition needed. If it is, shouldn't it simply be the method used to determine key facilities for selling transmission service? The current definition at a minimum needs to consider IROL as potential TFC instead of just system facilities.

The Flowgate definition should add "monitored transmission" in front of Facilities. A generator is also a facility but is not included as part of a flowgate definition. Also, bullet one should start with: "Designated paths on…" It is not a point.

The definition of PTDF also needs to be modified - it could be modified to read: "In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer."

The definition of OTDF also needs to be modified - it could be modified to read: "In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more transmission facility element removed from service (outaged)." This is to ensure that PTDF is not confused with Generator Transfer Distribution Function (GTDF), as a generator is also a facility.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

- MOD-001:

- R1: We question the appropriateness of retaining the calculation of TTC within the MOD series standards rather than inclusion with the FAC series standards to assure consistency with the calculation of Total Transfer Capability (TC). While FERC did not explicitly direct the ERO to develop the TTC in FAC-012 as the NOPR had proposed, it nonetheless directed that the short and long-term calculations be consistent with TC to the extent possible (Order 693 @ P1039). To achieve such consistency, and to avoid virtually identical requirements in 2 standards, it is our view that TTC calculation should be part of the FAC-012 standard.

  Further, we are unable to see the relevance of a Planning Coordinator's “planning area” in the TOP's determination of TTC and TSP's determination of ATC since the areas under the purview of a TOP, TSP and PC may differ among them. If an appropriate area needs to be included in the requirements then we would suggest the a Transmission Operator's area be specified for a TOP's determination of TTC, and a Transmission Service Provider's area be specified for a TSP's determination of ATC.

- R3: We do not agree that R3.1 to R3.6 are sub-requirements. They are attributes that need to be included (at a minimum) in the ATCID. The violation severity level of R3 would then depend on the number of these attributes not included in the ATCID. Additionally, the IRC is concerned with the drafting teams approach to explicitly defining the method (ATCID) to be used to consolidate the required information. While we may agree the ATCID may be conducive for audit purposes, requirements should only specify “what” is required and leave the “how” it is to be compiled to the responsible entity.

- R6: We do not see the need to include Planning Coordinator in the list of entities to inform before a TSP implements a revised or new ATCID.

- R8: We suggest splitting this into two requirements - one for the TOP on TTC and one for TSP on ATC. Having a requirement to hold two entities to each comply with a specific part of it creates difficulties for developing violation risk factors, measures and violation severity level, and for compliance audit.

- R9: There are markets which do not require reservations and hence it does not make sense that the ATC values should be reviewed or posted per this requirement because by the very nature of such market operations, the ATC/TTC values are pretty much static and only change when system conditions change and have a direct impact on the values. The requirement must be modified with a qualifier statement so that these values need to be reviewed and posted for the following conditions and the fact that these can be applied to areas with and without reservations. The following qualfier could be added: "The ATC shall be updated by the Transmission Service Provider if (a)The ATC/TTC values have changed since the last update and the TSP can provide documentation as to why these numbers had not changed until then and (b) The other TSP has changed the ATC/TTC values." The main intention of the FERC Order 693 regarding the MOD standards was to ensure consistency, transparency, and communication and we believe that even though there is a mention of "frequency of posting" - section 1057, Order 693 - "…include a requirement that ATC be updated by all transmission providers on a consistent time interval…" the requirement, as is written now, is very prescriptive and the frequency of posting, especially the hourly postings/certifications is not required and is very cumbersome and extremely burdensome. The correct ATC/TTC values should always be posted on the appropriate website as this is a reliability consideration – this is what the standard requirement should capture - but the frequency of posting should be a NAESB requirement and not a "reliability standard".R10: The requirement as written is difficult to understand. Suggest to delete the phrase "to each requester" to add clarify. Further, similar to our comments on R3, R10.1 to R10.15 are the data to be provided. They are not sub-requirements.

MOD-004

R1: R1.1 to R1.3 are elements to be included in the CBMID, they are not sub-requirements.

R2: The TSP should post the CBMID on the OASIS rather than making it available to the selected entities only.

R5: We are unable to see the role of a Transmission Planner in setting the value of CBM. TP is a recipient of the CBM value for considering in its transmission planning process, not the setter. The TSP should be performing the tasks listed in R5 upon receiving requests from the LSEs.

R7: Accordingly, the TP should not be responsible for providing supporting data used for allocating CBM.

- MOD-008
- R1: R1.1 to R1.4 are elements to be included in the TRMID, they are not sub-requirements. R1.5 is a legitimate sub-requirement; it doesn't need to be changed.

R4: The TSP should post the TRMID and related information on the OASIS rather than making it available to the requesting TSPs only.

MOD-030

- R2.3 does not identify that TFC can be limited by an IROL but it should. If selling transmission service really requires development of a reliability standard, R2.4 should be modified to require updating the TFC any time the underlying determinants, such as facility ratings, change.

- R3.4 requires that a TOP include all modeling and topology for Facilities in the Reliability Coordinator Area. For a small TOP within a large RC, this may be overkill. R3.5 arbitrarily requires a model to include 3 contiguous busses from the tie-line into synchonously connected systems and R3.6 requires at least an equivalent representaiton further in than that. These are not appropriate or acceptable methods for determining modelling detail level. There exist commercially available modeling packages that can be used to determine the impacts of the external system and how much detail should be kept. There should be a requirement(s) that establishes thresholds such as percent impact of flows on the TOP system for removal of facilities from the external footprint. If the impact exceeds that threshold, then the external facility should be modeled in detail.

This standard should not include any requirements on the Transmission Operator. R2 should be a requirement on the Transmission Service Provider. Ultimately, they will have to work with the TOP to identify the flowgates and it is in the best interest of the TOP to help the TSP but the requirement should not apply to the TOP. This drafting team should work with the appropriate drafting team developing TOP requirements to ensure that there is a requirement for the TOP to communicate limits to the TP. R3 should not apply to the TOP. It should apply to the TSP. The TSP should use system limit inputs such as SOL and IROL given by the TOP to determine TFC. Ultimately, R3 should be a simple requirement for the TSP to use the system limits determine by the TOP per FAC standard to define the TFC. No sub-requirements are then required.

MOD-028

R2.2 is not clear - modeling "beyond Reliability Coordination Areas" may not be feasible in many cases, especially when entire second or third tier RCs have to be modeled - adjacent RC area modeling is a must but modeling of beyond adjacent RC areas should be at the discretion of the Transmission Operator. Also, R2.1 through R2.3 are model parameters and not requirements per se.

MOD-029

R2.1.5 is worded inconsistently with the rest of the bullet points. It should read as: "System disturbances for stability studies by a three-phase-to-ground fault on all modeled “Extra High Voltage (EHV)” buses adjacent to the major interconnection point of the modeled Posted Path should not render the system unstable".

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

MOD-001:

If the SDT accepts our comments in (3) above, then the following Measures should be revised:

M1: changed to reflect new requirement language accordingly.

M7: Split this measure into two to reflect the split of R8 into two requirements.

M10: This measure needs to be reworded for clarity, as follows: "The Transmission Service Provider shall provide a copy of the dated request for ATC data as well as evidence to show it responded to that request (such as logs or data) within fourteen calendar days of receiving a request, and the requested data items were made available in accordance with R10."

MOD-004:

Assuming the above comments are accepted,

M2: Need to be changed to reflect posting on the OASIS.
M7: Need to change Transmission Planner to Transmission Service Provider.
M9: Remove Transmission Planner from this measure.

VSL for R1 should be changed to be associated with the number of elements (R1.1 to R1.3) not included.

MOD-008:

Assuming the above comments are accepted,

M4: Need to be changed to reflect posting on the OASIS.

VSL for R1 should be changed to be associated with the number of elements (R1.1 to R1.4) not included.

MOD-030

The Violation Risk Factor for R3, R5, R6, and R8 should be changed from Medium to Lower. In order for these requirements to have a medium VRF, according to the VRF criteria in Drafting Team Guidelines, they would have to directly affect the electrical state or capability of the bulk electric system or ability to effectively monitor and control the bulk electric system or in the planning time frame, or if violated, could under emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of capability of the bulk electric system. There is no direct link from this requirement because selling trasnmission service does not affect actual flows. The transmission service would have to be scheduled by the customer which he may not do and then the schedule has to be approved by all TPs on the path, and source and sink BA. These entities have tools that allow them to determine if a schedule should flow and the Reliability Coordinator acts as a backstop. When the RC issues a TLR, Interchange Distribution Calculator even reallocates and halts new schedules during regardless of how long ago the transmission service was sold. Thus, several other activities have to occur or fail to occur to impact directly the BES and thus, there is no direct link.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☒ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments: Selling transmission service is not really a reliability issue. It is a commercial issue. Additionallly, FERC is very clear in its 693 Order that the primary purpose of ordering these changes to the reliability standards is to create transparency, eliminate undue discrimination, and ensure consistency. If existings standards were contributing to these problems, ordering these changes would be appropriate. However, using the reliability standards to effect these goals is an inappropriate use. Do we want to say anything like that here or let it go?

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

MOD-028 and MOD-029: We raise the question on the "purpose" of both MOD-028 and MOD-029, both of which are defined as: "…to support reliable system operations". Is the methodology to be used for calculating transfer capability for "Transmission services", or for supporting reliable system operations? For entities which do not provide physical point-to-point transmission services, like the IESO, why should we be held responsible for meeting the standard requirements for calculating TTCs that support transmission services?

MOD-030

Several requirements are written with sub-requirements that are really criteria. These sub-requirement should be incorporated directly into the requirement itself. Otherwise, we risk having the Commission assign a VRF to something that really is criteria or explanatory text. Some examples include R2, R3, and R4. R2 could be written as:

R2. The TSP shall identify Flowgates for use in the AFC process based on the following minimum criteria.

- Flowgates should be defined with contingencies that are used in operations and planning studies for the associated time horizon.

-At least the first Flowgates identified as limits to transfer from or to all adjacent BA within the TOP transmission system.

-Any modeled Flowgate that has been subjected to Interconnection wide congestion management procedure or another TP using methodogolies defined by MOD-28 or MOD-29 has requested that meets one of the following two criteria.

-Any generator within the Transmission Service Provider area has at least a 5% PTDF or OTDF impact on the Flowgate when delievered to aggregate load in the TSP areas or

-A transfer from any BA within the TSP's area to a BA adjacent that has at least a 5% PTDF or OTDF impact on the Flowgate

We agree with that the remaining sub-requirements of R2 are really sub-requirements.

R4 should be rewritten as because the assumptions should be specifically designed and it is too vague:

R4 The Transmission Service Provider shall use contingencies from it planning and operating studies for the applicable Time Horizon and should model the impact of point-to-point Transmission Service as:

- When the source or sink are specified in the reservation, the Transmission Service Provider should model the reservation in the following order of importance:

  1. Model the reservation using the actual source and sink in the model.
  2. Map to an "equivalence" or
  3. Map to the interface point with the adjacent upstream Transmission Service Proivder as the Source the adjacent downstream Transmission Service Provider as the Sink.

- When the source or sink are not specified, the Transmission Service Provider should map the reservation to the interface point with the adjacent upstream Transmission Service Proivder as the Source the adjacent downstream Transmission Service Provider as the Sink.

R2.2 should also require a change to flowgates any time there is a topological change that impacts one.

The VSLs for R1 need to be defined according to the Violations Severity Levels Development Criteria document. R1 fits the procedure/program category. Lower, Moderate and High VSLs should be defined based on some of the criteria being included.

Counterflows - the treatment of counterflows is mentioned in all the MOD standards - MOD-001, MOD-028, MOD-029, and MOD-030 - all the formulae incorporate conterflows into the calculations but there seems to be a disconnect between the formulae and R5 of MOD-001 - if counterflow treatments are left to the discretion of the TSP in the respective ATCIDs, then why does R5 of MOD-001 exist - can it not be written as: "When determining the impact of counterflows in the determination of non-firm ATC or Available Flowgate Capability (AFC), the Transmission Service Provider shall apply counterflow treatment consistent with the Transmission Service Provider's ATCID". The counterflow treatment should also be consistent with transmission planning studies.

We agree with the NERC SDT that the TRM methodology should not be prescriptive.

MOD-008 (TRM) has a requirement when entities have a zero value for TRM - R1.5 of MOD-008 states that: "If TRM is zero for all the time periods…".There is no similar language for MOD-004 when entities have a zero value for CBM.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
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| **Contact Organization:** | SPP |
| **Contact Segment:** | 2 |
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| Jim Castle | NYSIO | **NPCC** | 2 |
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| Ron Falsetti | IESO | **NPCC** | 2 |
| Matt Goldberg | ISO-NE | **NPCC** | 2 |
| | | | |
| Anita Lee | AESO | **WECC** | 2 |
| Steve Myers | ERCOT | **ERCOT** | |
| William Phillips | MISO | **RFC+** | |
| | | **MRO+** | |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☒ Yes

☐ No

If "Yes," please identify your concerns. Comments: Tying the implementation date with the various regulatory approvals for the MOD standards could mean effective dates can be varied across North America. A definitive effective date should be set that accounts for the time needed for appropriate regulatory approvals.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

- Incorrect Definition: MOD-004

CBM is intended to be used for accessing generation from external sources to meet the LSE's PLANNED capacity installation requirement. The word "planned" should be inserted in the definition for GCIR.

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- Total Flowgate Capability does not consider that an IROL may be a limit.
- Is the Flowgate Methodology definition needed. If it is, shouldn't it simply be the method used to determine key facilities for selling transmission service? The current definition at a minimum needs to consider IROL as potential TFC instead of just system facilities.

The Flowgate definition should strike the word monitored and add transmission in front of Facilities. The NERC Glossary of Terms gives a generator as an example of Facility and the current definition would then allow a generator to define a flowgate. Also bullet one should start with: A designated set of transmission facilities. It is not a point.

MOD-029

The SRc notes that Order 890, P. 212 requires that the NERC Drafting Team address "counterflows" but does not provide direction as to the meaning of that term. As the term is often used interchangeably to mean actual flows of energy, scheduling of energy or reservations of transmission for possible scheduling of energy, the Team suggests that the NERC ATC Drafting Team clarify the meaning of the term as well as how it integrates into each proposed standard. Specifically, the NERC Drafting Team should clarify such items as: 1) is it a flow, a schedule or a reservation, 2) does it change characteristics based on the time frame examined (E.g. is it a reservation before it becomes a schedule?), 3) is it uni-directional or bi-directional. The term is used in numerous calculations but as presented is too vague to calculate rendering the formula opaque.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

- For MOD-001:
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- R6: We do not see the need to include Planning Coordinator in the list of entities to inform before a TSP implements a revised or new ATCID.
- R8: We suggest splitting this into two requirements - one for the TOP on TTC and one for TSP on ATC. Having a requirement to hold two entities to each comply with a specific part of it creates difficulties for developing violation risk factors, measures and violation severity level, and for compliance audit.
- R9: There are markets which do not require reservations and hence it does not make sense that the ATC values should be reviewed or posted per this requirement because by the very nature of such market operations, the ATC/TTC values are pretty much static and only change when system conditions change and have a direct impact on the values. The requirement must be modified with a qualifier statement so that these values need to be reviewed and posted for the following conditions and the fact that these can be applied to areas with and without reservations. The following qualfier could be added: "The ATC shall be updated by the Transmission Service Provider if (a)The

ATC/TTC values have changed since the last update and the TSP can provide documentation as to why these numbers had not changed until then and (b) The other TSP has changed the ATC/TTC values." The main intention of the FERC Order 693 regarding the MOD standards was to ensure consistency, transparency, and communication and we believe that even though there is a mention of "frequency of posting" - section 1057, Order 693 - "…include a requirement that ATC be updated by all transmission providers on a consistent time interval…" the requirement, as is written now, is very prescriptive and the frequency of posting, especially the hourly postings/certifications is not required and is very cumbersome and extremely burdensome. The correct ATC/TTC values should always be posted on the appropriate website as this is a reliability consideration – this is what the standard requirement should capture - but the frequency of posting should be a NAESB requirement and not a "reliability standard".

- R10: The requirement as written is difficult to understand. Suggest to delete the phrase "to each requester" to add clarify. Further, similar to our comments on R3, R10.1 to R10.15 are the data to be provided. They are not sub-requirements.
- MOD-004
- R1: R1.1 to R1.3 are elements to be included in the CBMID, they are not sub-requirements.
- R5: We are unable to see the role of a Transmission Planner in setting the value of CBM. TP is a recipient of the CMB value for considering in its transmission planning process, not the setter. The TSP should be performing the tasks listed in R5 upon receiving requests from the LSEs.
- R7: Accordingly, TP should bot be responsible for providing supporting data used for allocating CBM.
- MOD-008
- R1: R1.1 to R1.4 are elements to be included in the TRMID, they are not sub-requirements. R1.5 is a legitimate sub-requirement; it doesn't need to be changed.
- • MOD-29
- •
- • R1.6.
- • We suggest this bullet be deleted. This is already addressed in R2 wherein the modeling process is dictated. In the RSP methodology, "peak load forecasts" are not used to stress the system; rather, load and generation are simulated to stress the system to its greatest capacity. There are cases when the highest forecasted load may not stress the system to its greatest utilization – which is the goal of the R2 under the RSP.
- • R2.3
- • We suggest correcting "…as determined by R1.2.1…" to read "…as determined by R2.1."

- • R5.

- • The language describing Native Load should be changed from "reserved" to "encumbered." Encumbered is the word most frequently used in conjunction with OASIS to describe this condition. The same change should apply to GF sub F.

- • The language describing Grandfathered capacity includes the defined terms "Firm" and "Transmission Service." Use of these words as defined terms is inconsistent throughout the proposed standards. They should either be changed here to a lower case or all applicable areas in each proposed standard should be changed to the defined term.

- MOD-030

- R2.3 does not identify that TFC can be limited by an IROL but it should. If selling transmission service really requires development of a reliability standard, R2.4 should be modified to require updating the TFC any time the underlying determinants, such as facility ratings, change.

- R3.4 requires that a TOP include all modeling and topology for Facilities in the Reliability Coordinator Area. For a small TOP within a large RC, this may be overkill. R3.5 arbitrarily requires a model to include 3 contiguous busses from the tie-line into synchronously connected systems and R3.6 requires at least an equivalent representation further in than that. These are not appropriate or acceptable methods for determining modeling detail level. The two involved TSPs for the given transmission system and adjacent transmission system should determine the appropriate level of modeling detail needed in the adjacent transmission system.

- This standard should not include any requirements on the Transmission Operator. R2 should be a requirement on the Transmission Service Provider. Ultimately, they will have to work with the TOP to identify the flowgates and it is in the best interest of the TOP to help the TSP but the requirement should not apply to the TOP. This drafting team should work with the appropriate drafting team developing TOP requirements to ensure that there is a requirement for the TOP to communicate limits to the TSP. R3 should not apply to the TOP. It should apply to the TSP. The TSP should use system limit inputs such as SOL and IROL given by the TOP to determine TFC. Ultimately, R3 should be a simple requirement for the TSP to use the system limits determine by the TOP per FAC-014-1 standard to define the TFC. No sub-requirements are then required.

- R10 requires that all TSPs convert their AFCs and TFCs to ATC and TTC values. The IRC supports an allowance for entities whose tariffs do not use ATC and TTC to meet this requirement through a tool rather than manual calculations. There is no value added to the customer to have ATC and TTC values for transmission service that is sold on a AFC and TFC basis. Therefore these TSPs should not be burdened with the added expense and effort to convert the values manually. The IRC proposes the following language, "The Transmission Service Provider shall convert or provide a tool to convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths."

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

For MOD-001:

If the SDT accepts our comments in (3) above, then the following Measures should be revised:

M1: changed to reflect new requirement language accordingly.

M7: Split this measure into two to reflect the split of R8 into two requirements.

M10: This measure needs to be reworded for clarity, as follows: "The Transmission Service Provider shall provide a copy of the dated request for ATC data as well as evidence to show it responded to that request (such as logs or data) within fourteen calendar days of receiving a request, and the requested data items were made available in accordance with R10."

MOD-004:

Assuming the above comments are accepted,

M7: Need to change Transmission Planner to Transmission Service Provider.
M9: Remove Transmission Planner from this measure.

VSL for R1 should be changed to be associated with the number of elements (R1.1 to R1.3) not included.

MOD-008:

Assuming the above comments are accepted,

VSL for R1 should be changed to be associated with the number of elements (R1.1 to R1.4) not included.

MOD-29

M1.
M1 inaccurately calls for production of “models” used to derive TTC. As there are multiple conditions under MOD-29, R2 where a model does not dictate the predicate for TTC, M1 should be reworded to state “…shall produce the models, contracts, nomograms, reports or study results…”

Corresponding to:
1) Models in R2.1, R2.2. and R2.5;
2) Contracts in R.2.3 and R2.6;
3) Nomograms in R2.4;
4) Reports or studies in R2.7 and R2.8.

M1.3
We suggest correcting M1.3 from “…as stated in R1.1 through R.12…” to “…as stated in R1.1 through R1.12…”

M4.

If "M1" above is adopted, M4 is duplicative of M1 and should be deleted.

VSL R5, R6, R7, R8
These VSLs call for only a "severe" determination. They also mandate that the TSP "use" all the elements defined. However, the TSP will not "use" all the defined elements if they are not applicable. Thus, if a TSP does not "use" all elements defined because all the elements were not applicable – the TSP is in violation for not including null elements in its calcuation.

We suggest these be rewritten to state: "The Transmission Service Provider did not use all affected elements as defined in…." This approach should help clarify that "zero" as an integer is an acceptable entry and that only those variables "affected" need be reported or acted upon.

MOD-030
The Violation Risk Factor for R3, R5, R6, and R8 should be changed from Medium to Lower. In order for these requirements to have a medium VRF, according to the VRF criteria in Drafting Team Guidelines, they would have to directly affect the electrical state or capability of the bulk electric system or ability to effectively monitor and control the bulk electric system or in the planning time frame, or if violated, could under emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of capability of the bulk electric system. There is no direct link from this requirement because selling trasnmission service does not affect actual flows. The transmission service would have to be scheduled by the customer which he may not do and then the schedule has to be approved by all TSPs on the path, and source and sink BA. These entities have tools that allow them to determine if a schedule should flow and the Reliability Coordinator acts as a backstop. When the RC issues a TLR, the Interchange Distribution Calculator even reallocates and halts new schedules regardless of how long ago the transmission service was sold. Thus, several other activities have to occur or fail to occur to impact the BES and thus, there is no direct link.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☒ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments: MOD-030
Selling transmission service is not a reliability issue. It is a commercial issue. Additionallly, FERC is very clear in its 693 Order that the primary purpose of ordering these changes to the reliability standards is to create transparency, eliminate undue discrimination, and ensure consistency. If existings standards were contributing to these problems, ordering these changes would be appropriate. However, using the reliability standards to effect these goals is an inappropriate use because they do not affect reliability.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

MOD-029 RATED SYSTEM PATH TTC, ETC & ATC

1) The SRC supports retention of the requirement(s) in R2.2 that accommodate paths which are "flow limited" by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing practices without re-inventing the wheel where no such effort is required to meet FERC's goals of transparency and consistency.

2) The SRC supports retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.

3) The SRC supports retention of the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.

4) The SRC supports retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts, associated litigation and potential renegotiation of associated operational agreements while supporting FERC's mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation metholdogies is required.

MOD-030

Several requirements are written with sub-requirements that are really criteria. These sub-requirements should be incorporated directly into the requirement itself. Otherwise, we risk having the Commission assign a VRF to something that really is criteria or explanatory text. Some examples include R2, R3, and R4. R2 could be written as:

R2. The TSP shall identify Flowgates for use in the AFC process based on the following minimum criteria.

- Flowgates should be defined with contingencies that are used in operations and planning studies for the associated time horizon.

-At least the first Flowgates identified as limits to transfer from or to all adjacent BA within the TOP transmission system.

-Any modeled Flowgate that has been subjected to Interconnection wide congestion management procedure or another TP using methodogolies defined by MOD-28 or MOD-29 has requested that meets one of the following two criteria.

-Any generator within the Transmission Service Provider area has at least a 5% PTDF or OTDF impact on the Flowgate when delievered to aggregate load in the TSP areas or

-A transfer from any BA within the TSP's area to a BA adjacent that has at least a 5% PTDF or OTDF impact on the Flowgate

We agree with that the remaining sub-requirements of R2 are really sub-requirements.

R4 should be rewritten as because the assumptions should be specifically designed and it is too vague:

R4 The Transmission Service Provider shall use contingencies from it planning and operating studies for the applicable Time Horizon and should model the impact of point-to-point Transmission Service as:

- When the source or sink are specified in the reservation, the Transmission Service Provider should model the reservation in the following order of importance:

1. Model the reservation using the actual source and sink in the model.
2. Map to an "equivalence" or
3. Map to the interface point with the adjacent upstream Transmission Service Proivder as the Source the adjacent downstream Transmission Service Provider as the Sink.

- When the source or sink are not specified, the Transmission Service Provider should map the reservation to the interface point with the adjacent upstream Transmission Service Proivder as the Source the adjacent downstream Transmission Service Provider as the Sink.

R2.2 should also require a change to flowgates any time there is a topological change that impacts one.

The VSLs for R1 need to be defined according to the Violations Severity Levels Development Criteria document. R1 fits the procedure/program category. Lower, Moderate and High VSLs should be defined based on some of the criteria being included.

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RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| **NERC Region** (check all Regions in which your company operates) | | **Registered Ballot Body Segment** (check all industry segments in which your company is registered) |
| ☐ ERCOT | ☒ | 1 — Transmission Owners |
| ☐ FRCC | ☐ | 2 — RTOs and ISOs |
| ☒ MRO | ☒ | 3 — Load-serving Entities |
| ☐ NPCC | ☐ | 4 — Transmission-dependent Utilities |
| ☐ RFC | ☒ | 5 — Electric Generators |
| ☐ SERC | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ SPP | ☐ | 7 — Large Electricity End Users |
| ☐ WECC | ☐ | 8 — Small Electricity End Users |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

   ☐ Yes

   ☒ No

   If "Yes," please identify your concerns. Comments:

2. If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

   Incorrect Definition:

3. If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

   Incorrect Requirement: R.3.5 of MOD-030-1, arbitrarily requiring modeling data and topology for at least three contiguous busses is too prescriptive. Standards should set out goals and use measures to determine if these goals were achieved. How the goals are best achieved are best determined by the Transmission Owner/Operator. If the goal is to improve loop flow, then the measure should be developed that ascertains loop flow improvement. A prescriptive number of busses does not insure that loop flow is appropriately captured.

4. The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

   Incorrect Measure or Compliance Element:

5. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If "Yes," please explain why and provide supporting information.
   Comments:

6. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

   Comments: For Standard MOD-030-1, R2.1.2, the phrase "first three limiting" is too prescriptive and should be removed.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

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    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

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Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☒ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments: Standard MOD-001-1 Requirement R1, footnote 1

A primary intent of these related standards to is promote consistency among Transmission Service Providers in the calculation of ATC. This goal of consistency is violated by the provisions of footnote 1, which would permit a single Transmission Service Provider to use different methodologies on the same Posted Path at different points in time. MidAmerican also feels that there is absolutely no way each of the three methodologies would yield consistent and equivalent results.
While we acknowledge that Order No. 693 found that it is "not necessary to require a single industry-wide ATC calculation methodology" (Order No. 693, Paragraph 1030), the Commission's intent was that ATC be calculated in a manner that "provides predictable and sufficiently accurate, consistent, equivalent, and replicable ATC calculations regardless of the methodology used by the region" (Order No. 693, Paragraph 1034). Only under unusual conditions would there be a reason for a single

Transmission Service Provider to use differing ATC methodologies on different Posted Paths, and only rarely would there be a reason to use different methods on the same Posted Path at different points in time. Permitting these deviations would make it essentially impossible to verify the calculations of the Transmission Service Provider, because it would be difficult to determine what methodology was in effect on which Posted Path at which point in time. In addition, these deviations would permit manipulation of ATC calculations.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: Although the standards are heading in the right direction, two things that must be done are to create an on-the-path, off-the-path methodology for determining which facilities to include when determining an ATC and the standard must create rules on how to include partial path reservations. If these two things are not done in a consistent manner, the enitire process falls apart.

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Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment** (check all industry segments in which your company is registered) |
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
| ☐ FRCC | ☒ | 2 — RTOs and ISOs |
| ☒ MRO | ☐ | 3 — Load-serving Entities |
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Group Comments (Complete this page if comments are from a group.)

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**Contact Organization:**

**Contact Segment:**

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**Contact E-mail:**

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>
> **MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.
>
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>
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>
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>
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The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
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    - TFC
    - AFC (firm and non-firm)
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*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

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- Incorrect Requirement:
- MOD-001-1:
- • R.3.3 of MOD-001-1 should read "The identity or a link to the identity of the Planning Coordinator…associated with each Flowgate…". Reasoning: Common practice is to include flowgates rather than all facilities. Also, the list of Flowgates may get updated often (monthly). We suggest including a link to the Flowgates. Having this link will reduce the burden of having to update the ATCID on a monthly basis.
- MOD-004-1:
- • R4.2 of MOD-004-1 should be reworded as: "…simultaneously, or a methodology to meet resource adequacy criteria that assumes an aggregated need for CBM, or all firm ATC or AFC has been allocated…" Reasoning: Assuming each LSE (or group of LSE) submits its GCIR based on 1day/10year criteria, preserving the "sum" of all such requests is equal to planning according to such 1day/10year emergency happens in all LSEs (or groups of LSE) at the same time. In a large capacity sharing pool such as MISO, this is to plan way beyond 1day/10year criteria. We recognize the right of LSE having special requirement based on state requirement. However, the original lingual doesn't allow MISO to continue its current methodology ("max" instead of "sum") even if all LSEs agree to do so. An alternative could be allowed by the standard such that regional TSP's like ISO/RTO's that develop a consensus method with stakeholders of evaluating CBM needs on a regional basis may base CBM on LSE load forecasts and firm generation commitments, and have the CBM calculated by the TSP as necessary to ensure resource reliability criteria.
- • R4.1.2.2 of MOD-004-1 should read "As a minimum standard, classify … greater than 3% on an OTDF Flowgate or 5% on a PTDF Flowgate as a significant impact".

- • For R4.2.2. of MOD-004-1, since AFC is determined from CBM, CBM for each Flowgate should not be dependent on AFC. CBM can be big enough to drive AFC to zero or negative. This simply means that resource adequacy criteria can't be met, and no capacity will be available on that Flowgate (which is what the original wording of this requirement was trying to do anyway). Therefore we believe CBM should not be set to AFC, it should be left at whatever value was calculated. Suggestion language: For Flowgates, Entities may use a static number, which requires its CBMID describe the procedure of utilizing CBM, or set the CBM for each Flowgate equal to the lesser of:

- • For R4.3 and R5.3 of MOD-004-1, see the comment for R4.2.2. The same argument applies to these requirements.

- • For R5.2 of MOD-004-1, see the comment for R4.2. The same rewording is recommended.

- MOD-030-1:

- • MOD-030-1, R2 should read "…Transmission Operator or Transmission Service Provider…" After hearing some industry comment that including this "or" (as we have in multiple comments) may not be possible in a standards requirement, we look to the team to determine how best to include some flexibility in which entity is required to meet the standard, to respect the varying distribution of work across these regions.

- • R3 of MOD-030-1 should read "The Transmission Service Provider shall use a Transmission model to determine…" And then an additional criteria bullet could be added that states "Contains data provided by the Transmission Operator, to the extent that it is available." ☐ the wording on this comment is very draft

- • R.3.5 of MOD-030-1, arbitrarily requiring modeling data and topology for at least three contiguous busses is too prescriptive. This requirement could be rewritten to as "Contains modeling data and topology agreed upon by each adjacent Reliability Coordinator Area and the Transmission Operator or the Transmission Service Provider." However it is worded, somehow the requirement has to be set based on the intention of improving loop flows, not getting to a certain number of busses.

- • R4. of MOD-030-1 needs to be rewritten. First, we believe NERC standard shouldn't intervene with how TSP treats PTP reservations. TSP has the best knowledge of their system and knows what treatment gives the best AFC forecast. Second, if this treatment has to be discussed anyway, we believe that having some flexibility is better than requiring the use of source/sink. For example, one transaction going across multiple OASIS will have the same source/sink along the path. Using source/sink could result in double-counting, triple counting, etc. Another example is that, in large TSP area such as MISO, OASIS POR/POD or Source/Sink can't represent real-time market central dispatch. Reservations/schedules only determine overall MISO interchange, not interchange for MISO internal BAs. In other cases, some other method may be more desirable. If getting the most accurate calculation (while not hindering transparency) is the intent of the team, then the way in which the reservation is modeled should not solely depend on the information in the request, but rather on a methodology that can be reviewed by everyone. Suggested language? (maybe in the same line as "a methodology that can be reviewed by everyone"

- • For R10. of MOD-030-1, the text describing "P" should read: "…as a minimum standard, a Flowgate is considered 'impacted' by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or 5% on a PTDF Flowgate".

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Incorrect Measure or Compliance Element:

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☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

General comments on MOD's:

•All Violation Risk Factors in MOD-001, -004, -008, and -030 should be Lower as none represent a risk of cascading outages if they are not met.

•Many of the "sub-requirements" listed in the standards should either be bulleted items under the standard or removed and placed in an Appendix, rather than being made actual requirements themselves. For example, in MOD-001, R3, the requirements R3.1 through R3.6 could be just bulleted or placed in an Appendix with R3 reworded to say that the ATCID must address all the items in Appendix xx.

MOD-001-1:

•MOD-001, R1, should read "…Transmission Operator or Transmission Service Provider…" After hearing some industry comment that including this "or" (as we have in multiple comments) may not be possible in a standards requirement, we look to the team to determine how best to include some flexibility in which entity is required to meet the standard, to respect the varying distribution of work across these regions.

•In MOD-001-1, R6, the method of notification should include an option for public posting such as OASIS.

•MOD-001-1, R10. 14 days can be too short when there are multiple requests pending. There should be a queue process. It is reasonable to request a response time for the first request in the queue, but not on all simultaneous requests.

•MOD-001-1, R10.12 Since there is a requirement to provide this information in 14 days, this needs to be clarified to say the information that must be provided is the rules for calculating counterflow used in the calculation of ATCs, not the actual MW values themselves. A database of the actual MW values for any given calculation would be extremely large and could not be provided, nor would it serve any real purpose.

MOD-004-1:

•For Standard MOD-004, R3 and R4, A monthly value is extremely difficult to administrate and implement in the ATC calculation. Such a requirement will subject the TSP to significant increases in cost (the vendor has to provide new code and the frequency of TSP updates would drastically increase). GCIR calculation part has to do a lot more studies. Midwest ISO suggests leaving it to each region to decide on the time intervals.

•MOD-004, R3.1 – This section should be updated to clarify what is meant to be requested. For example, it states "requested for each month for each year for the next ten year period." Do you really want 120 months worth of requests, or 12 monthly requests and 9 yearly? Suggested wording "for each month for the first 12 months and for each year for the remainder of the ten year period"

•MOD-004, R3.2 – Why should LSE update every month if CBM is only calculated once per year? We suggest that these timelines be clarified.

•MOD-004, R9 -- Should be adjusted so that it explicitly states that only the timing requirements for the Real-Time market only will be waived. For example, the Day-Ahead Market timing requirements cannot be waived.

MOD-008-1:

- MOD-008, R1.5: "If TRM is zero for any of the time periods listed…"

MOD-030-1:

•MOD-030-1, change R1 language to affect M1 regarding criteria used by Transmission OwnerR1, TSP should not be responsible for actively notifying changes made to criteria set by TO. Suggested wording is "… shall include … (ATCID) the practice or a link to the practice the TSP uses for adding Flowgates".

•For Standard MOD-030-1, requirement R.2.1.1. is redundant with the definition of Flowgate given in the "definitions" section. This requirement should be removed, or at least reworded to read "…may be a Flowgate."

•For Standard MOD-030-1, R2.1.2, the phrase "first three limiting" is too prescriptive and should be removed. For example, if the most limiting first contingency transfer is a large value, say 10,000, adding first three limiting elements/contingency combinations is not necessary. If the requirement can't be deleted, we suggest adding wording that sets a transfer level such that the first three constraints that cause the FCITC to fall under that level will be captured. Also, "source sink combinations" needs to be further defined as a calculation entity of any size could have thousands of these possible combinations. Also, if this in-depth study is required, the frequency in R2.2 should be decreased (as this is a minimum standard).

•MOD-030-1, R2.3 rating issues, refer to comments from SRC, which says "MOD-030-1, R2.3 does not identify that TFC can be limited by an IROL but it should. If selling transmission service really requires development of a reliability standard, R2.4 should be modified to require updating the TFC any time the underlying determinants, such as facility ratings, change.".

•MOD-030-1, R5.1. This is not always the best practice. For example, while using PSS/E model, some outage remote to the TSP service area can cause the case to not solve and the TSP has to either use DC power flow solution or ignore the outage. The impact from ignoring a remote outage on the accuracy of AFC is much smaller than that from using DC power flow. The TSP has to temporarily block the outage to achieve overall better accuracy. Suggestion wording is "… have been executed, to the extent it helps improve the AFC calculation accuracy." Understanding that the ability to measure deviations may become an issue, the wording could be adjusted to state "… have been executed, except for any outages that, if included, would force the calculation into a less accurate solution technique." We realize that the suggested wording is not perfect, but we're hoping that the team understands our intention and can adjust it accordingly.

•MOD-030-1, R5.2. Should add "to the extent they are available" to the end. Not all MISO third parties have that data available.

• In MOD-030-1, R8 and R9, "ATC" should be "AFC".

•MOD-030-1, R6.3 and 6.4, should say a 3% distribution factor or an impact of 3% of the total MW of the PTP request, not 3% of the distribution factor.

•MOD-030-1, R10 should be revised to say "The Transmission Service Provider shall convert or provide a tool to convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths."

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment (check all industry segments in which your company is registered)** |
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**Contact Telephone:**

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| Additional Member Name | Additional Member Organization | Region* | Segment* |
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- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

MID supports the comments submitted by the Sacramento Municipal Utility District ("SMUD") on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: MID supports the comments submitted by SMUD on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

MID supports the comments submitted by SMUD on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

MID supports the comments submitted by SMUD on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments: MID supports the comments submitted by SMUD on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: MID supports the comments submitted by SMUD on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)


**Group Name:** Midwest Reliability Organization (MRO)

**Lead Contact:** Tom Mielnik

**Contact Organization:** MRO

**Contact Segment:** 10

**Contact Telephone:** 563-333-8129

**Contact E-mail:** tcmielnik@midamerican.com


| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Neal Balu | WPS | MRO | 10 |
| Terry Bilke | MISO | MRO | 10 |
| Robert Coish | MHEB | MRO | 10 |
| Carol Gerou | MP | MRO | 10 |
| Jim Haigh | WAPA | MRO | 10 |
| Ken Goldsmith | ALTW | MRO | 10 |
| Pam Oreschnick | XCEL | MRO | 10 |
| Dave Rudolph | BEPC | MRO | 10 |
| Eric Ruskamp | LES | MRO | 10 |
| Michael Brytowski | MRO | MRO | 10 |
| Ron Slagel | MISO | MRO | 10 |
| Kun Zhu | MISO | MRO | 10 |
| 27 Additional MRO members | not mentioned above | MRO | 10 |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

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- Identify ATC methodology used
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- Share ATC data and information

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**Capacity Benefit Margin (CBM)**

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- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

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- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

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- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: a. The Posted Path definition in MOD-001-1 that indicates it includes any "Balancing Authority to Balancing Authority interconnection" and then R1 of the standard says ATC must "select one ATC methodology… for each Posted Path" and then R2 states that the TSP "shall calculate ATC values…using the ATC methodologies." As a result, the TSP must calculate ATCs and post those ATCs and all the Posted Paths. Many of these BA to BA paths are not useful paths to post either for commercial or reliability reasons. Therefore the language in the definition or the requirements should clarify that the definition provides the items such as any BA to BA path, path on which there has been curtailment, etc. that may qualify for posting or else the requirements should be changed to indicate that postings are not developed for all such paths but are developed for those paths that such postings are required for commercial and/or reliability reasons.

b. Presuming that changes are made per our comment 2.a. so that the Posted Path definition is only including items that are eligible for Posted Path and does not include items that must be posted, we note that the Posted Path definition in MOD-001-1 does not cover all the instances of a posted path in that there are flowgates that should be set up for reliability purposes to cover a system constraint that is not properly represented in the transmission service request evaluation process and is not covered by the three items listed. Service may not have been denied, curtailed, or interrupted yet due to the constraint because the facilities were not included in a flow gate. The MRO recommends that the following be included as an item in the definition "4) Any flowgate."

Posted Path Definition: The MRO asks the SDT to consider adding some language onto the end of Item (2) to qualify the statement. Something like "…and for which congestion is expected to occur." This is needed because it could have been an unusual operating condition (multiple generator/line outages) that caused the curtailment and that condition is not expected to occur again.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

MOD-001, R1, should read "…Transmission Operator or Transmission Service Provider…" After hearing some industry comment that including this "or" (as we have in multiple comments) may not be possible in a standards requirement, we look to the team to determine how best to include some flexibility in which entity is required to meet the standard, to respect the varying distribution of work across these regions.

MOD-001-1 R1: The requirement to select one method for each path needs to be clarified. Some MRO members use the rated system path method for CA-CA hard-tie calculations and then use the flowgate method facilities expected to be congested. The requirement to translate AFC to ATC for each path could result in a conflict if the CA-CA path limit is based upon the rated path method when a flowgate limits the path rating when AFCs are converted to ATCs. The MRO recommends that the SDT clarify the requirement as necessary to explain how this conflict will be resolved.

MOD-001-1 R.3.3 should read "The identity or a link to the identity of the Planning Coordinator and Transmission Operator…associated with each Flowgate…". Reasoning: Common practice is to include flowgates rather than all facilities. Also, the list of Flowgates may get updated often (monthly). We suggest including a link to the Flowgates. Having this link will reduce the burden of having to update the ATCID on a monthly basis.

MOD-001-1 R3.6: The MRO does not understand what "allocation" is. The MRO asks that the SDT clarify this word in the standard.

MOD-001-1, R6, the method of notification should include an option for public posting such as OASIS.

MOD-001-1, R10. 14 days can be too short when there are multiple requests pending. There should be a queue process. It is reasonable to request a response time for the first request in the queue, but not on all simultaneous requests.

MOD-001-1 R10: The extent of data to be provided upon request is potentially too extensive to be workable or justified.

MOD-001-1 R10: The requirement should be to only provide your own data. Otherwise there can be issues of confidentiality with providing third party data.

MOD-001-1 R10: There should be a restriction that it is only required to provide data used in AFC calculations. This may be implied but it should be made clear.

MOD-001-1 R10.1: The need to provide transmission "additions and retirements" should be restricted to only those used in AFC calculations. The open planning process is the correct venue to request info on planned facilities, not the ATC standards.

MOD-001-1 R10.4" "details" needs to be expanded upon. The MRO does not understand what this means.

MOD-001-1, R10.12. Since there is a requirement to provide this information in 14 days, this needs to be clarified to say that information that must be provided is the rules for calculating counterflow used in the calculation of ATCs, not the actual MW values because the MW would be too much data to provide in 14 days.

MOD-004-1 does not seem to provide for those Transmission Service Providers who have a practice of maintaining zero CBM due to reserve sharing arrangements in which little outside assistance has been assumed in developing their historical generation reserve requirements. The MRO recommends that a requirement be added to MOD-004-1 outlining what descriptions must be provided in the CBMID to describe zero CBM practices such as under R3.1. For the SDT's information, MAPP historically has self provided its reserve requirements without outside assistance and therefore has historically set CBM to zero.

MOD-004, R3 and R4, A monthly value is extremely difficult to administrate and implement in the ATC calculation. Such a requirement will subject the TSP to significant increases in cost (the vendor has to provide new code and the frequency of TSP updates would drastically increase). GCIR calculation part has to do a lot more studies. Midwest ISO suggests leaving it to each region to decide on the time intervals.

MOD-004, R3.1 – This section should be updated to clarify what is meant to be requested. For example, it states "requested for each month for each year for the next ten year period." Do you really want 120 months worth of requests, or 12 monthly requests and 9 yearly? Suggested wording "for each month for the first 12 months and for each year for the remainder of the ten year period"

MOD-004, R3.2 – Why should LSE update every month if CBM is only calculated once per year? We suggest that these timelines be clarified.

MOD-004-1 R4.2 should be reworded as: "…simultaneously, or a methodology to meet Resource Adequacy criteria that assumes an aggregated need for CBM, or all firm ATC or AFC has been allocated…" Reasoning: Assuming each LSE (or group of LSE) submits its GCIR based on 1day/10year criteria, preserving the "sum" of all such requests is equal to planning according to such 1day/10year emergency happens in all LSEs (or groups of LSE) at the same time. In a large capacity sharing pool such as MISO, this is to plan way beyond 1day/10year criteria. We recognize the right of LSE having special requirement based on state requirement. However, the original lingual doesn't allow MISO to continue its current methodology ("max" instead of "sum") even though all LSEs agree to do so.

MOD-004-1 R4.1.2.2 should read "As a minimum standard, classify … greater than 3% on an OTDF Flowgate or 5% on a PTDF Flowgate as a significant impact".

MOD-004-1 R4.2.2. - since AFC is determined from CBM, CBM for each Flowgate should not be dependent on AFC. CBM can be big enough to drive AFC to zero or negative. This simply means that resource adequacy criteria can't be met, and no capacity will be available on that Flowgate (which is what the original wording of this requirement was trying to do anyway). Therefore we believe CBM should not be set to AFC, it should be left at whatever value was calculated. Suggestion language: For Flowgates, Entities may use a static number, which requires its CBMID describe the procedure of utilizing CBM, or set the CBM for each Flowgate equal to the lesser of:

MOD-004-1 R4.3 and R5.3 - , see the comment for R4.2.2. The same argument applies to these requirements.

MOD-004-1 R5.2 - see the comment for R4.2. The same rewording is recommended.

MOD-008-1 R1.1 indicates that one uncertainty that can be considered is "Aggregate Load forecast uncertainty (not included in determining generation reliability requirements)." The MRO understands that a concern is making sure that items are not double covered by CBM and TRM, however, this sub requirement is incorrect and needs to be modified because the same load forecast uncertainty will result in uncertainty in generation planning that may require a CBM amount--in other words we have to allow for additional transmission capacity to deliver generation reserves in an emergency when loads are higher. But that same load forecast uncertainty will result in uncertainty in the loadings on transmission facilities and will impact the need for having a margin to cover for loads on the system at all times. The MRO recommends that the SDT either delete the words "(not included in determining generation reliability requirements)" from the item or else revise the words to say something like the following which better describes what should be excluded, that is "(TRM is not to include impacts of load forecast uncertainty on CBM.)"

MOD-008-1 R1.2: The need to state that consistent assumptions are used for TRM as is used in the planning process needs to be clarified. The SDT should clarify that short-term TRM should be consistent with operational planning while long-term TRM should be consistent with long-term planning. The MRO recommends that the language here be modified to be similar to R8 of MOD-001-1 to say, "A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in ANY ASSOCIATED OPERATIONS STUDIES OR PLANNING STUDIES FOR THE TIME PERIOD STUDIED." The words in caps are the new words that are added in place of the words in the draft standard for that part of R1.2.

MOD-008, R1.5: "If TRM is zero for any of the time periods listed…..".

MOD-008-1 R3. and R4 call for certain responsible entities to provide information in seven days. This is not enough time to allow for delays due to vacations and other absences. In smaller utilities, especially this seven days is not realistic. The MRO asks that the SDT increase this time and suggests 30 days as a more reasonable number.

MOD-030-1, change R1 language to affect M1 regarding criteria used by Transmission OwnerR1, TSP should not be responsible for actively notifying changes made to criteria set by TO. Suggested wording is "… shall include … (ATCID) the practice or a link to the practice the TSP uses for adding Flowgates".

MOD-030-1 R2.1 has a typo, the word "for" should be deleted from the requirement.

MOD-030-1 R2.1.2 is too limiting in requiring that "at a minimum the first three limiting Elements/Contingency combinations within the Transmission Operator's system are included as Flowgates." The MRO believes there are smaller Transmission Operators with surrounding larger utiltiies with higher loaded facilities where this requirement would unnecessarily result in the establishment of additional flowgates. The MRO is not sure an across-NERC requirement for flowgate criteria is required; however, if the SDT gets comments to the contrary, the MRO suggests that the Transmission Provider be required to have documentation which includes an explanation for not using any of the three limititations. In this way, there is not a lot of needless work yet there is a provision which will result in protecting reliability. If TPs develop the documentation, if there are reliability issues, it will be obvious and the TPs will act to create the new flowgates.

MOD-030-1, R2 should read "…Transmission Operator or Transmission Service Provider…" After hearing some industry comment that including this "or" (as we have in multiple comments) may not be possible in a standards requirement, we look to the team to determine how best to include some flexibility in which entity is required to meet the standard, to respect the varying distribution of work across these reqions.

MOD-030-1, requirement R.2.1.1. is redundant with the definiition of Flowgate given in the "definitions" section. This requirement should be removed, or at least reworded to read "…may be a Flowgate."

MOD-030-1, R2.1.2, the phrase "first three limiting" is too prescriptive and should be removed. For example, if the most limiting first contingency transfer is a large value, say 10,000, adding first three limiting elements/contingency combinations is not necessary. If the requirement can't be deleted, we suggest adding wording that sets a transfer level such that the first three constraints that cause the FCITC to fall under that level will be captured. Also, "source sink combinations" needs to be further defined as a calculation entity of any size could have thousands of these possible combinations. Also, if this in-depth study is required, the frequency in R2.2 should be decreased (as this is a minimum standard).

MOD-030-1 R2.1.3: Before the first "OR" the MRO recommends that a qualifier like "experiencing at least 24 instances of congestion" and "expected to be a congested facility in the planning horizon" to limit the instances in which parties have to post a flowgate. If a facility has TLR because of some weird system condition not expected to occur again, it would be waste of time to post a flowgate for that.

MOD-030-1 R2.2 requires that the list of Flowgates be updated on a quarterly basis. Yet R2.4 requires that TFC only be updated on an annual basis. The MRO recommends that R2.2 be changes to updating on an annual basis. The quarterly basis is needless extra work.

MOD-030-1, R2.3 rating issues, refer to comments from SRC, which says "MOD-030-1, R2.3 does not identify that TFC can be limited by an IROL but it should. If selling transmission service really requires development of a reliability standard, R2.4 should be modified to require updating the TFC any time the underlying determinants, such as facility ratings, change.".

MOD-030-1 R2.3: The MRO is aware of some processes that require that regional groups to approve new flowgate TTCs prior to posting so as to have a regional reliability and equity review prior to posting the new flowgate TTCs. If a flowgate line rating increases, there can be a time-lag until the regional groups approve the new operating study and operating guide required before the new TTC can be posted. Some words are needed to allow for the time lag for regional review since it benefits reliability and equity.

MOD-030-1 R3 should read "The Transmission Service Provider shall use a Transmission model to determine…" And then an additional criteria bullet could be added that states "Contains data provided by the Transmission Operator, to the extent that it is available."

MOD-030-1 R.3.5, arbitrarily requiring modeling data and topology for at least three contiguous busses is too prescriptive. This requirement could be rewritten to as "Contains modeling data and topology agreed upon by each adjacent Reliability Coordinator Area and the Transmission Operator or the Transmission Service Provider."

However it is worded, somehow the requirement has to be set based on the intention of improving loop flows, not getting to a certain number of busses.

MOD-030-1 R4 needs to be rewritten. First, we believe NERC standard shouldn't intervene with how TSP treats PTP reservations. TSP has the best knowledge of their system and knows what treatment gives the best AFC forecast. Second, if this treatment has to be discussed anyway, we believe that having some flexibility is better than requiring the use of source/sink. For example, one transaction going across multiple OASIS will have the same source/sink along the path. Using source/sink could result in double-counting, triple counting, etc. Another example is that, in large TSP area such as MISO, OASIS POR/POD or Source/Sink can't represent real-time market central dispatch. Reservations/schedules only determine overall MISO interchange, not interchange for MISO internal BAs. In other cases, some other method may be more desirable. If getting the most accurate calculation (while not hindering transparency) is the intent of the team, then the way in which the reservation is modeled should not solely depend on the information in the request, but rather on a methodology that can be reviewed by everyone. Suggested language? (maybe in the same line as "a methodology that can be reviewed by everyone"

MOD-030-1 R5.1 indicates that the TSP is to include all expected outages, additions, and retirements in effect in the TSP's area, adjacent TSPs, and any TSPS with coordination agreements have been executed. The MRO believes this is a nice goal but the TSP cannot be liable for a penalty for failing to include all expected outages, additions, and retirements that it hasn't been told about. The MRO recommends that "and known" be added to the requirement.

MOD-030-1, R5.1. This is not always the best practice. For example, while using PSS/E model, some outage remote to the TSP service area can cause the case to not solve and the TSP has to either use DC power flow solution or ignore the outage. The impact from ignoring a remote outage on the accuracy of AFC is much smaller than that from using DC power flow. The TSP has to temporarily block the outage to achieve overall better accuracy. Suggestion wording is "… have been executed, to the extent it helps improve the AFC calculation accuracy." Understanding that the ability to measure deviations may become an issue, the wording could be adjusted to state "… have been executed, except for any outages that, if included, would force the calculation into a less accurate solution technique." We realize that the suggested wording is not perfect, but we're hoping that the team understands our intention and can adjust it accordingly.

MOD-030-1 R5.1: The word "all" should be deleted. Only the one included in the calculation should be required. Also, same comment on the "additions and retirements" language. The need to provide transmission "additions and retirements" should be restricted to only those used in AFC calculations. The open planning process is the correct venue to request info on planned facilities, not the ATC standards.

MOD-030-1, R5.2. should add "to the extent they are available" to the end. Not all MISO third parties have that data available.

MOD-030-1 R6.1.3.1.1: Peak load forecast for the first 31 days needs to be clarified. The MRO is aware of some that prepare a peak load forecast only for the next 7-10 days. In such cases the load used in projections for days 11-31 is the monthly value. The accuracy of daily forecasts beyond the next 7-10 is questionable. Maybe the language should specifically allow this.

MOD-030-1 R6.2: "impact" needs to be defined a bit more. Some MRO members define impact as something like 85% of positive impacts, 100% if the flowgate has had firm TLR. Also, "expected to be scheduled" should be clarified because some Transmission Providers include all reservation impacts in AFCs. The "expected" language adds a complexity that will be hard to meet and for that reason the language should be deleted.

MOD-030-1 R6.3 and R6.4 provide a 3% but do not define what it is 3% of. The MRO recommends that the SDT add language to explain how it is calculated --what is the calculated in terms of percent of what. This also applies to R7.2 and R7.4 of the same standard.

MOD-030-1 R7.1: Again "impact" needs some more definition. Some presently use something like 50% counterflow in non-firm AFCs. Also, the language states that non-firm AFCs should only bring in non-firm reservations. The MRO believe this is wrong. Firm reservations NEED to be considered in non-firm AFCs.

MOD-030-1 R8 refers to postbacks but no definition is provided. The SDT should either provide a NERC definition, repeat the NAESB definition, or paraphrase a definition. Without it, the MRO and other responsible entities are not sure what is the requirement.

MOD-030-1, R8 and R9, "ATC" should be "AFC".

MOD-030-1 R10 is not understandable. The MRO has no idea what is meant by this Requirement and how to implement the requirement. The SDT should substantially increase the words that explain this requirement.

MOD-030-1 R10., the text describing "P" should read: "…as a minimum standard, a Flowgate is considered 'impacted' by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or 5% on a PTDF Flowgate".

MOD-030-1 R10: In addition to the comments already supplied, explicit consideration of the concern raised above regarding those cases where a party uses CA-CA path limits to set hard tie limits and yet also posts flowgate limits where AFCs need to be converted to ATCs. The requirement to translate AFC to ATC for each path could result in a conflict if the CA-CA path limit is based upon the rated path method when a flowgate limits the path rating when AFCs are converted to ATCs. The MRO recommends that the SDT clarify the requirement as necessary to explain how this conflict will be resolved.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☒ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

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The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☐ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

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☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

1. Since a TTC limit may be due to thermal or stability limit, those limits that are considered IROL's should be required to be identified in the methodology.

2. If no inputs to an ATC have changed then an update should not be required. (MOD-001)

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment** **(check all industry segments in which your company is registered)** |
| ☐ ERCOT | ☒ | 1 — Transmission Owners |
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**Lead Contact:**

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**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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- Calculate TRM
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    - ATC (firm and non-firm)
- Share TTCs

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**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
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    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

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- Method-specific ATCID elements
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*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

   ☒ Yes

   ☐ No

   If "Yes," please identify your concerns. Comments: Not sure if this question is asking for additional time beyond the proposed implementation date or just a confirmation of what is proposed. I feel the proposed effective date langauge is sufficient. As mentioned below, the drafting team should review the effect date langauge in all six MODs to ensure consistency.

2. If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

   Incorrect Definition: In MOD-001, Posted Path is included in defined terms. This is a duplication of "Posted path" in 18 CFR Part 37.6 (b)(1)(i). Suggest that throughout these MODs, replace the term Posted Path with "paths required to be posted" or "paths requiring posting" or "paths for which ATC is calculated".

3. If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

   Incorrect Requirement: See comments below.

4. The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

   Incorrect Measure or Compliance Element: The use of the term "horizon" in the violation risk labels has caused some confusion because of its use in ATC horizons (different time periods for which ATC is calculated in a specific manner).

5. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

   ☒ Yes

   ☐ No

   If "Yes," please explain why and provide supporting information.
   Comments: Throughout, these standards assert that the calculation of ATC is a reliability matter. This is incorrect. ATC is a commercial product, a commodity that is offered by transmission service providers, sold to transmission customers, and sometimes traded amongst transmission customers. FERC requires jurisdictional transmission providers to calculate and post ATC. 18 CFR Part 37.6 contains the standards of ATC calculation and

posting. It is not reasonable to be subject both to FERC enforcement of the CFRs and to NERC enforcement of these overlapping standards.

In the west, reliability is not impacted by the miscalculation, posting, or sale of ATC. It is when transactions are scheduled that reliability is potentially impacted. Improper TTCs impact reliability. Failure to evaluate proposed transactions and their impacts to the transmission system impact reliability. It is reasonable that NERC reliability standards cover the calculation of TTC, and some aspects of CBM and TRM.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: MOD-001-1, A., 3. the stated Purpose contains noble goals which are not required for reliable system operation but for viable commercial activity. Reliable system operations are impacted by incorrect TTC values and uncoordinated transaction scheduling activities.

MOD-001-1, A., 4. applicability, Transmission Service Provides calculate ATC. Transmission Operators (in the near term) and Transmission Planners (in the longer term) calculate TTC.

MOD-001-1, B., R1, Transmission Operators calculate transfer capability (TTC) of facilities within its TO area. Transmission Planners calculate transfer capability (TTC) of facilities within their TP areas. Transmission Service Providers calculate ATC for those paths that they are required to, choose to, or are asked to post.

MOD-001-1, B., R2 is a good requirement, but for commercial reasons, not reliability reasons. Transmission customers need to have access to more “granular” ATC closer to real-time. Also, why were weekly ATC values not included?

MOD-001-1, B., R3 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability. This requirement to create a separate document creates an undue burden on the industry - transmission customers will have two different documents to review, and transmission service providers will have two different documents to maintain.

MOD-001-1, B., R3 the term “Facility” is used several times in MOD-001-1. The NERC glossary says facility is “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”. In R3.3 the requirement to list the Transmission Operators and Planning Coordinators for every facility under the TSP’s tariff is burdensome and does not have value. Hundreds of facilities make-up even small systems. R3.3 should say "for each path for which the Transmission Service Provider calculates ATC, list the corresponding Transmission Operator and Transmission Planner and Reliability Coordinator".

MOD-001-1, B., R3.6 “Allocation methodologies” – it is not clear to what this means? Perhaps the following: "For paths where multiple Transmission Service Providers share capacity or have rights, describe how the capacity is allocated among providers", or words to that effect.

MOD-001-1, B., R4 is not needed, it is already covered in R3.2. Since R4 leaves it open to each TSP's choice and requires them to document it, perhaps as a suggestion, the requirement could be to have the TSP do as they say they do in their Attachment C. The requirement might be rewritten to say "the TSP utilizes counter schedule information in their firm ATC calculations as specified in their Attachment C." Then, if the TSP fails to document or to do as they say they do, this could be a violation of the requirement.

MOD-001-1, B., R5 is not needed, it is already covered in R3.2. Since R4 leaves it open to each TSP's choice and requires them to document it, perhaps as a suggestion, the requirement could be to have the TSP do as they say they do in their Attachment C. The requirement might be rewritten to say "the TSP utilizes counter schedule information in their firm ATC calculations as specified in their Attachment C." Then, if the TSP fails to document or to do as they say they do, this could be a violation of the requirement.

MOD-001-1, B., R6 is not necessary. Revisions to Attachment C are to be filed and posted.

MOD-001-1, B., R7 Attachment C is already required to be posted (available) for any entity to review, subject to CEII concerns.

MOD-001-1, B., R8 does not read clearly. It can be interpreted as requiring any restudy of TTC to include previously used data rather than data that is reflective of the conditions of the time period being studied. Perhaps the requirement was for data used in the determination of TTC should be the most accurate, up-to-date data available and should reflect the expected conditions of the period of time under study.

MOD-001-1, B., R9 is not a reliability concern. In addition, it is unduly burdensome. Current and accurate ATCs are a commercial concern. In addition, performing 168 hourly calculations every hour when neither TTC nor ETC has changed, benefits no one and is costly. The commercial requirement should be to require the recalculation of hourly ATC once a day and whenever either TTC or ETC changes for any period of time between this hour and the next 168 hours. Also, require the recalculation of daily ATC once a day for the next 30 days and whenever either TTC or ETC changes for any period of time between this hour and the next 31 days.

MOD-001-1, B., R10, this requirement for data sharing between reliability entities is a good concept. However, as currently worded, all the burden to supply data is incorrectly placed totally upon the TSP and not on the Transmission Operator or Transmission Planner. Much of the data listed is critical for proper TTC calculation which the TSP may not have access to. The TSP calculates ATC based on upon TTC supplied by the Transmission Operator and/or Transmission Planner. This requirement does not specify how the request is made or how the response or provision of data is dated. The corresponding measurement, M9, implies that all data items requested will be supplied within 14 days, but requirement states that the TSP will begin to make available at the 14 day mark. In addition, change first sentence words "…days of a request of any Transmission…" to "…days of a request made by any Transmission…" to read more in-line with the intent. Additionally, the requirement borders on a run-on sentence. Suggest moving the list of allowable requesters from R10 to be a sub-requirement R10.xx. The list of data is not all inclusive, there may other information needed. By each item, list what entity would have that data – TSPs would have ATC and ETC information, operators and planners would power flow data, etc.

MOD-004-1, A., Capacity Benefit Margin is a use of the transmission system that is requested by a load serving entity. This standard contains requirements for the interactions between the LSE and the transmission provider. These requirements are largely commercial in nature and should be under NAESB development. Reliability standards concerning CBM should only require LSEs to acquire minimum CBM to ensure service to load.

MOD-004-1, A., 6. Effective Date language is not but should be exactly the same for all six MOD draft standards.

MOD-004-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider's CBM methodology. This requirement to create a separate document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and providers would have to maintain two different documents.

MOD-004-1, B., R2 is not necessary. Revisions to Attachment C are to be filed and posted (available) for any entity to review, subject to CEII concerns.

MOD-004-1, B., combine R3.3 language into R3.1.

MOD-004-1, B., R3.2 it seems more reasonable for the requirement to read "LSE shall review any active CBM requests at least every six months and submit updates as required."

MOD-004-1, B., R4 uses active verb "shall set….as follows:" but R4.1 says "Determine the amount of CBM…". To align the language a little better perhaps R4 should simply say "…the Transmission Service Provider shall:". In that way the TSP shall "determine" (R4.1), shall "set" (R4.2), shall "increase" (R4.3).

MOD-004-1, B., R4.3 contemplates the case where there is insufficient capacity to meet all the CBM requests on a particular path, but there is no discussion on allocation of limited capacity to the requests. Is NAESB working on this aspect? If not, is it a TSP's discretion to develop a CBM allocation methodology?

MOD-004-1, B., R8, R9, R10, M11, M12, M13 use of the terms "tag" or "Interchange Transaction Tag" which is inconsistent with NERC INT and NAESB CI BP standards where specific reference to "tag" or "e-Tag" has purposefully been avoided in those standards. The term Request For Interchange (RFI) refers to a collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink BA. Or the term Arranged Interchange refers to The state where the Interchange Authority has received the Interchange information (initial or revised) and has distributed that information for reliablity assessment. I believe that in these requirements, Arranged Interchange is the more appropriate langauge.

MOD-004-1, B., R10 requires, without exception, that all submitted Arranged Interchange using CBM must be approved. This would force TSPs to potentially approve malformed transactions possibily citing incorrect contract arrangements, incorrect connectivity, etc. Perhaps the requierment could state the TSP shall approve all valid requests to schedule CBM. The drafting team might consider requiring the TSP or other approval entities to supply a valid reason for denying a CBM schedule.

MOD-008-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider's TRM methodology. This requirement to create a separate document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and TSPs two different documents to maintain.

MOD-008-1, B., R1.1 suggest modifying to read: "For each path or flowgate that ATC or AFC is calculated, describe how each of the following components of uncertainty are used in calculating TRM for each of the ATC time horizons (if not applicable, indicate as such):" The words "ATC time horizons" could be used to eliminate the need for R1.4.

MOD-008-1, B., R.3 what "request" is being referred to? Should it read "…seven calendar days of a request from:"? Or should "of a request" be removed as a typo?

MOD-008-1, B., it seems that R1, 2, and 5 could be merged together into a new R1 TRM calculation and documentation. R3 and 4 could merged together into a new R2 on TRM data sharing.

MOD-029-1 inclusion of the Rated System Path methodology is greatly needed and appreciated. The drafting team was wise in including it and should be thanked for their efforts.

MOD-029-1 suggest reordering R4 to be R1.

MOD-029-1 R1 (modeling requirements) should include the statement that the data listed below should reflect the expected conditions for the applicable time period.

MOD-029-1 R1.6 change "peak load forecast" to "applicable load forecast" since some SOLs, and ultimately TTCs, may be based upon light load conditions.

MOD-029-1 delete R2.7 as it, in its current form, does not provide the entire paradigm contained in the WECC's Procedures For Regional Planning Project Review And Rating Transmission Facilities.

MOD-029-1 in R6, is the "non-firm capacity reserved for NITS" the same as Secondary Network Service (i.e., NN-6)?

MOD-029-1 in R7 & R8, what are "Postbacks"? This term is not used in the west.

MOD-029-1 in R5, R6, R7, & R8, calculation of ETC and ATC are commercial concerns and should be addressed in business practice standards NAESB and enforced through FERC's adoption of those business practice standards into the CFR.

MOD-029-1 in R8 the requirement says we are to use the same formula for all horizons – this is incorrect. For the real-time, same-day time frame, we release all unscheduled capacity as non-firm ATC. As such, the formula would read:

ATCNF = TTC – Scheduled ETCF – Scheduled ETCNF – CBMS – TRMU + Counter-schedulesF + Counter-schedulesNF

MOD-029-1 in R8 the ETCF definition should be changed from "…existing non-firm commitments…" to "…existing non-firm commitments…"

MOD-030-1 it is unreasonable for TSPs to convert AFC values into ATC values simply because FERC regulations fail to contain the term AFC. For large systems using this methodology, posting thousands of ATC values benefits no one if AFC values can give transmission customers a better picture of available capability of the transmission system.

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<table>
<tr><th colspan="3">Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
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<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment<br>(check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☒ NPCC<br>☐ RFC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
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</table>

Group Comments (Complete this page if comments are from a group.)


**Group Name:** NPCC Regional Standards Committee

**Lead Contact:** Guy V. Zito

**Contact Organization:** Northeast Power Coordinating Council

**Contact Segment:** 10

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| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
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| Alan Adamson | New York State Reliability Council | NPCC | 9 |
| Kathleen M. Goodman | ISO-New England, Inc. | NPCC | 2 |
| Biju Gopi | IESO | NPCC | 2 |
| Roger Champagne | Hydro-Quebec TransEnergie | NPCC | 2 |
| Greg Campoli | New York-ISO | NPCC | 2 |
| Ralph Rufrano | New York Power Authority | NPCC | 1 |
| David Kiguel | Hydro One Networks | NPCC | 1 |
| Ron Falsetti | IESO | NPCC | 2 |
| Murale Gopinathan | Northeast Utilities | NPCC | 1 |
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## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

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The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

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**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

MOD-001

- 1. R1: The reference to the Planning Coordinator's planning area in R1 is not appropriate; the reference should be to the Transmission Operator's operating area.

- 2. R3.3: Since this standard deals with short-term Transmission Service, the reference to Planning Coordinator should be removed from R3.3, R6.1 and R6.4

- 3. R3.3: This should be reworded to be clear that the TOP is providing input (TTC or TFC) to the TSP to perform ATC calc. Also suggest removing reference to a 'tariff' since non-jurisdictional entities may not have a tariff. Suggest the following language: The identity of the Transmission Operators that provide data on each Posted Path for use by the Transmission Service Provider in calculating ATC. Acronyms TOP, TFC, and TSP need to be defined in the Background Information on p. 3. The abbreviation "calc." should be spelled out.

- 4. R4 and R5 should reference both the terms counter-schedules and counterflow throughout the requirements

5. R9 (or at a minimum the Measure for R9) must be modified to be clear that if TSP can demonstrate that no inputs to the ATC calculation have changed that an update of a 'timestamp' on an ATC value is not required. Suggested options for the language in R9: "Each TSP shall update ATC at a minimum on the following frequency, except that if all inputs to ATC are unchanged no update is required:" OR "Each TSP shall update ATC at a minimum on the frequencies listed below. However, if all inputs to ATC are unchanged no update is required."

MOD-029

- 1. R1.10 refers to EHV without it being a defined term and different regions could define EHV to be different voltage levels; suggest one of the following actions be taken: (a) include the desired kV level of the BPS system in the standard, (b) remove the reference to EHV entirely, (c) add a NERC glossary term. EHV should be defined in the Background Information on p.3 and be understood to be applicable to and restricted to the BPS irrespective of that voltage level. That definition must also include the BPS voltage level it refers to.

  2. R2 language could be interpreted that all N-2 contingencies must be considered in a TTC study. If the intent that the TTC study should consider all currently required planning criteria, a general reference should be made to the planning standards rather than try to summarize and reiterate those requirements here.

  3. R2.1.5 contains a very specific consideration for EHV contingencies to be considered in the TTC. Is there a reliability need for ALL regions to consider EHVs in this manner? If not, we suggest removing this requirement from the NERC standard, where it can be added in a more detailed regional standard if required by a particular region. EHV should be defined in the Background Information on p. 3; the definition must include the BPS voltage level it refers to.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:
1. VSL for MOD-028 R2 and R3 are is not clear if the 'errors' that are allowed are for a given TTC study or the allowed cumulative 'errors' since the last audit? (this language should also be clarified on comparable VSLs in MOD-029 and MOD-030). "Are is" in the first sentence needs to be corrected.

2. If suggestions in Question 3 and 6 are accepted, the associated Measures and VSLs will also need to be updated accordingly.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments: We would like confirmation from the Drafting Team that our interpretation of how the MOD-004 requirements can apply in areas that employ competitive wholesale markets in a manner that does not conflict with approved tariffs. In ISO/RTO markets where resource adequacy is performed by the ISO/RTO (i.e., an independent Balancing Authority), and by virtue of the market, the Transmission Service Provider does not offer transmission service in advance of physical flow, there is no ability for the LSE to 'request' CBM as defined in the standards. However, the reliability need for CBM by the LSE is satisfied by the market rules and associated tariffs. As such, the entities' CBMID would describe how the reliability needs of the LSEs, as relates to securing CBM is met and why there is no need for the LSE to 'request' CBM in the manner described in the standards. We would like confirmation from the Drafting Team that documentation of

CBMID in this manner – i.e., through specifying that an LSE need not "request" any particular transmission service – would satisfy the reliability requirements of MOD-004. LSE, and CBMID should be defined in the Background Information on p. 3.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

MOD-001

1.R1: While in many cases, the decision on which ATC methodology to use may be made jointly between the TSP and TOP. However, since you cannot have joint responsibility in the standard, the TOP is the appropriate Functional Model entity. Acronyms TSP, and TOP need to be defined in the Background Information on p. 3.

2.R8: Since this standard deals with short-term Transmission Service, the reference to planning studies should be removed from R8

3. R8 is an appropriate representation of the broad FERC requirement as-written that will force entities to make a conscious effort to ensure this consistency occurs. While the language is somewhat vague, we recognize that adding more detail would be unreasonably difficult. We would suggest that detail be added in the measures to provide examples of what a valid demonstration would be. For example, TOP/TSP may provide evidence to demonstrate that the source of the inputs used in the operational studies is the same as for the TTC/ATC studies. TOP and TSP need to be defined in the Background Information on p. 3.

MOD-028

1. R8 should be broken down into the different timeframes; sending TTC values used in hourly and daily ATC calculations seven days after being calculated is too late. Suggest: 8.1 within one calendar day of its determination for TTCs used in hourly and daily ATC calculations; 8.2 within seven calendar day of its determination for TTCs used in monthly ATC calculations.

MOD-030

1. R4 seems duplicative of MOD-001 R8

2. R6.3, 6.4 - The last sentence of R6.3 seems to belong in 6.4 not 6.3

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Rick Gonzales | | |
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| Telephone: 518 356 6116 | | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

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The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments: Not applicable.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: The NYISO supports the comments that the Northeast Power Coordinating Council ("NPCC") has submitted in response to this question.

Except as noted by the NPCC, all of the proposed definitions appear to be correct, assuming that NERC shares the NYISO's view that the definitions are sufficiently flexible to accommodate transmission providers that have obtained waivers from various FERC ATC and OASIS requirements and that do not offer transmission service based on physical reservations. As is discussed in more detail in response to Question Five, the NYISO, with FERC's approval, does not offer the kind of physical reservation transmission service that is the primary focus of Order Nos. 888 and 890. Nevertheless, the NYISO believes that its form of financial reservation transmission service fits within the framework of NERC's proposed definitions and standards.

It is very important to the NYISO that the proposed definition of "Existing Transmission Commitments" ("ETC") in MOD-028 and MOD-029 be interpreted flexibly. Many of the variables in the proposed ETC algorithm will not be applicable (or will always have a value of zero) in the NYISO's case. Specifically, the NYISO does not reserve capacity to serve native load growth, its customers do not hold physical reservations of point to point transmission service and have never taken Network Integration Transmission Service. On the other hand, the most important input into the NYISO's ATC calculations is "Transmission Flow Utlilization," which is based on the security constrained network powerflow solutions determined by the NYISO's day-ahead and real-time market software. It appears that the OS(F) variable in the proposed ETC algorithm is broad enough for the NYISO to include Transmission Flow Utilization information when calculating ETC (and thus ATC). To the extent necessary, the NYISO will provide additional information concerning its market software's computation of Transmisison Flow Utilization and its role in the ETC calculation in the NYISO's Available Transfer Capability Implementation Document ("ATCID").

If NERC disagrees with this interpretation then the NYISO requests that the MOD-028 and MOD-029 definition of ETC (and/or OS(F)) be revised to expressly allow ISO/RTO market software results, such as the NYISO's Transmission Flow Utilization information, to be considered in ETC calculations. Otherwise, the NYISO's existing method of calculating and posting ATC using market software outputs, which is a core feature of its FERC-approved market design, would be in conflict with NERC's standard. Additional information on the NYISO's financial reservation system is provided in the response to Question Five, below.

Finally, the definition of the OS(F) variable in the MOD-29 description of the ETC algorithm (at R9) may be slightly narrower in scope than the MOD-28 version because the MOD-29 definition does not include the language referencing "any other firm adjustments to reflect impacts on other Posted Paths as described in the ATCID" that is found in MOD-28. Because it is not clear why the two OS(F) definitions should be different, the NYISO asks that NERC revise the MOD-29 version to conform to the MOD-28 version.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement: The NYISO joins in, and supports, the comments submitted by the ISO/RTO Council ("IRC") in response to this question. The NYISO also supports the comments submitted by the NPCC. In particular, the NYISO strongly supports the NPCC's request that requirement R9 under MOD-01 be revised to clearly establish that ATC values need not be updated when the inputs to the ATC calculation have not changed. The NYISO also supports the NPCC's proposed revisions to the language of R9. The NYISO also has concerns on MOD-028 R3, R4 and R6 regarding the frequency of TTC calculations when inputs have not changed.

Except as noted by the IRC and NPCC, the NYISO does not believe that any of the proposed ATC standards are technically incorrect, so long as they are interpreted with sufficient flexibility to accommodate transmission providers that do not offer physical reservation transmission service.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element: The NYISO joins in, and supports, the comments submitted by the IRC in response to this question. The NYISO also supports the comments submitted by the NPCC.

Except as noted by the IRC and NPCC, the NYISO does not believe that any of the proposed measures or compliance elements are incorrect based on its expectation that NERC will interpret the ATC standards in a way that accommodates the needs of transmission providers that do not offer physical reservation transmission service.

If, however, NERC were to interpret the standards in a manner that was inconsistent with the use of FERC-approved non-physical forms of transmission service then the proposed compliance and sanction requirements would be inappropriate, inequitable, and unlawful. The NYISO does not believe that this is NERC's intent. In any event, NERC should not develop standards, or interpret them in a way, that would expose transmission providers to enforcement action for implementing tariffs that have been approved by FERC, and that Order No. 890 does not require be changed, simply because their tariffs differ from the standard Order No. 890 model.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments: The NYISO joins in, and supports, the comments submitted by the IRC in response to this question. The NYISO also supports the comments submitted by the NPCC.

Except as noted by the IRC and NPCC, the NYISO does not believe that there will be any conflict between the proposed ATC standards and anything in the NYISO's tariffs, the NYISO market design, or any FERC order related to them, provided that NERC interprets the standards with reasonable flexibility. So long as NERC takes this kind of approach, the NYISO expects to be able to apply its chosen NERC-approved ATC calculation methodology consistent with its use of a FERC-approved financial reservation transmission service model. The NYISO believes that NERC can interpret the standards with reasonable flexibility without reducing their technical accuracy or diminishing their effectiveness. Transmission providers that offer financial reservation transmission service would still be required to comply with all standards to the extent that they are applicable, exactly like transmission providers that offer physical reservation service.

By way of background, under the NYISO's financial reservation model, customers schedule transmission service "implicitly" when they submit energy schedules via the spot markets or arrange for bilateral transactions. There are no express reservations of physical transmission service and customers may schedule transactions between any two points, so long as doing so is not inconsistent with a security-constrained economic dispatch. All desired uses of the grid are scheduled to the extent that customers are willing to pay congestion charges, which can be hedged using financial rights. Stated differently, customers' ability to schedule transactions within New York is not limited by a pre-defined amount of ATC. Instead, the entire capacity of the New York State Transmission System is made available for both firm and non-firm service prior to the start of each market cycle. ATC is calculated and posted based on the transactions accepted in the day-ahead and real-time market. Consequently, the information conveyed by the NYISO's ATC postings is different than what is conveyed under physical reservation systems. As FERC has recognized, the NYISO's postings are really advisory "projections", albeit advisory projections that the Commission believes can be useful to customers.

Nothing in Order No. 890 required the NYISO to modify this system, no New York stakeholder has asked that it be changed, and there is no reason why it cannot be accommodated within a framework of rigorous and technically accurate ATC standards. NERC should not interpret the ATC standards in a way that would require the NYISO to perform functions that are inconsistent with its model or with past waivers it has received from FERC's OASIS/ATC regulations and related NAESB business practices. The NYISO identifies a limited number of requirements where this issue could arise in its response to Question Six, below. The NYISO believes that its ATC practices will comply with NERC's proposed requirements and that any differences between the details of its procedures and those of other transmission providers can be addressed in its ATCID.

For NERC's reference, the orders granting the NYISO waivers from various FERC OASIS and ATC requirements, and from related NAESB business practices, include New York Independent System Operator, Inc. 121 FERC 61,036 (2007); New York Independent

System Operator, Inc., 117 FERC ¶ 61,197 (2006); New York Independent System Operator, Inc., 94 FERC ¶ 61,215 (2001); and Central Hudson Gas & Electric Corp., et al., 88 FERC ¶ 61,253 at 61,803 (1999).

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: The NYISO joins in and supports the comments submitted by the IRC in response to this question. The NYISO also supports the comments submitted by the NPCC.

NERC's November 21 filing with FERC for an extension of time to complete the ATC standards development process described MOD-29 as a methodology used "exclusively" in the Western Interconnection. It also referred to MOD-28 as a methodology used "primarily" in the Southeast. Notwithstanding these descriptions, the NYISO is not aware of any NERC proposal to restrict the use of MOD-028 or MOD-29 to particular geographic regions. If, however, it is NERC's intent to impose such restrictions, the NYISO respectfully requests that NERC reconsider. Order No. 890 did not impose geographic restrictions or require all transmission providers in a given region to use the same methodology. Transmission Providers should be free to implement whichever methodology best suits them, their customers, and the needs of any markets they administer, so long as they comply with that methodology's requirements.

With respect to MOD-028, NERC should revise requirements R3 and R4 so that transmission providers are not required to re-calculate and re-post TTC at the specified intervals at times when none of the underlying inputs to the TTC calculation have changed. Under the NYISO system, TTC values do not change often. Accordingly, having to make more frequent TTC calculations would require the NYISO to adopt costly compliance measures that offer no benefit to its customers.

With respect to MOD-029, NERC should revise requirements R2.3 and R2.6 or, in the alternative, clarify in response to this comment that they do not apply to transmission providers, such as the NYISO, that do not offer physcial transmission rights based on contract-path reservations.

Similarly, with respect to MOD-001, NERC should revise requirements R10.3 through R10.8, and R10.14, or in the alternative, clarify in response to this comment that they do not apply to transmission providers, such as the NYISO, that use financial reservation models and thus will not have the information that the proposed requirements direct them to make available on request. Otherwise, the R.10 information requirements would effectively call on the NYISO to perform functions that FERC's waiver orders excuse it from performing and that would serve no purpose under the NYISO model.

More specifically:

R10.3 -- Unit Commitments and Dispatch Orders -- Under the NYISO system, ths information is only avaiable for the day-ahead and real-time market horizons. The NYISO will not have this information for the "operations planning" horizon as the proposed language would require.

R10.4 -- Firm and Non-Firm Network Integration Transmission Service details -- The NYISO's OATT currently requires the NYISO to offer a "financial" version of this service but no customer has ever requested it. The NYISO anticipates that it will propose to FERC that the Network Integration Transmission Service provisions of its OATT be eliminated well before MOD-001 is implemented. The NYISO will therefore not have any information on such reservations to make available in response to requests under R10.

R10.5 -- Confirmed firm and non-firm Transmission reservations -- In the NYISO system, customers do not make express, physical firm or non-firm transmission reservations. The NYISO will, therefore, not have any information on such reservations to make available in response to requests under R10.

R10.6 -- Grandfathered firm and non-firm contracted transmission capacity on an aggregated basis -- Although the NYISO honors the grandfathered transmission arrangements that are listed in Attachment L to its OATT it does not make express physical transmission reservations in connection with them. The NYISO will, therefore, not have any aggregated information on grandfathered capacity reservations to make available in response to requests under R10.

R10.7 -- Firm Roll Over Rights -- The NYISO's FERC-approved OATT has never included the pro forma OATT's roll-over right provisions. The NYISO will, therefore, not have any information on such rights to make available in response to requests under R10.

R10.8 -- Firm and Non-Firm Adjustments to Reflect Parallel Path Impacts -- Because the NYISO does not support physical firm or non-firm reservations, it has no procedures for gauging their parallel path impacts and will, therefore, not have information to make available in response to requests under R10.

R10.14 -- Flowgate values - The NYISO does not utilize any flowgates. The NYISO will, therefore, not have any flowgate-related information to make available in response to requests.

Except to the extent that they are addressed by the IRC or NPCC, the NYISO has no comments on MOD-004 or MOD-008. The NYISO has never set aside transmission capacity for CBM and does not intend to do so in the future. Consistent with NERC's expectation, the NYISO would explain this practice to the extent required in its ATCID. Likewise, the NYISO uses TRM and intends to comply with all of NERC's requirements related to it.

Thank you very much for your attention to these comments.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Shayleah LaBray | | |
| Organization: PacifiCorp | | |
| Telephone: 503 813 6176 | | |
| E-mail: shayleah.labray@pacificorp.com | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☒ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

PacifiCorp strongly supports the inclusion of a 12 month implementation period for these standards. The entities electing the Rated System Path Methodology will require this much needed period to assure proper review of the Posted Paths under their purview.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

The WECC MIC MIS ATC Drafting Team suggests in its comments that the NERC ATC Drafting Team clarify the meaning of the term "counterflows." PacifiCorp suggests that with regard to this comment, any changes to clarify the term "counterflows" should not undermine the flexibility allowed in the definition of the term "counter-schedules" in MOD-029 that states "Counter-schedules are adjustments to firm/non-firm Available Transfer Capability as determined by the Transmission Service Provider and described in its Available Transfer Capability Implementation Document.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

- Incorrect Requirement:
- PacifiCorp supports the WECC MIC MIS ATC Drafting Team December 14, 2007 comments suggested redraft langauge of R10 as follows:
- "R10. Upon request from another Transmission Service Provider, Planning Coordinator or Reliability Coordinator, each Transmission Service Provider shall provide from the below specified list, only that data requested and only that data already in existence and in the possession of the Transmission Service Provider from which that specified data is requested. Provision of all data is subject to confidentiality and security requirements."
- In addition, PacifiCorp suggests that the following sentence be added to the above proposed language that states "The requirements of R10.1-R10.15 should not be interpreted as a comprehensive list of what is required to be included in an ATC calculation."

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

PacifiCorp supports the following general and affirmative comments related to MOD-01 and MOD-029 submitted by the WECC MIC MIS ATC Drafting Team December 14, 2007.

GENERAL

1) Supports retention of the three methods recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028).

2) Strongly supports the retention of the proposed one-year implementation period.

3) Supports allowing NAESB to address all "posting" issues as they directly affect OASIS.

In addition, PacifiCorp suggests that any standards set forth herein be subject to an acknowledgement by NERC that compliance should not be required until the related NAESB standards are complete.

MOD-001 UMBRELLA

1) Supports allowing the use of more than one methodology for calculation of ATC by any one entity.

2) Supports allowing each entity to specify in its ATCID how it will treat counterflows / schedules. (R4., R5.)

3) Supports the aggregation of transmission capacity for grandfathered contracts when shared with neighboring requestors.

4) Supports the specifically limited universe of entities to which data sharing is required as prescribed in R10.

MOD-029 RATED SYSTEM PATH TTC, ETC & ATC

1) Strongly supports retention of the requirement(s) in R2.2 that accommodate paths which are “flow limited” by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing practices without re-inventing the wheel where no such effort is required to meet FERC’s goals of transparency and consistency.

2) Strongly supports retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.

3) Strongly supports the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.

4) Supports retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts, associated litigation and potential renegotiation of associated operational agreements while supporting FERC’s mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation metholdogies is required.

5) Supports the adoption of a definition for counterflow to clarify its application in each equation. In addition PacifiCorp echos its earlier comment in Section 2 that any changes to clarify the term counterflow should not undermine the flexibility allowed in the definition of the term "counter-schedules" in MOD-029.

NERC

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Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Chris Advena | | |
| Organization: PJM Interconnection LLC | | |
| Telephone: 610-666-4240 | | |
| E-mail: advena@pjm.com | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

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**Lead Contact:**

**Contact Organization:** .

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information

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The drafting team has created the following proposed standards:

> **MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.
>
> **MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.
>
> **MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.
>
> **MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.
>
> **MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.
>
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The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

   ☐ Yes

   ☒ No

   If "Yes," please identify your concerns. Comments: This time alloted is sufficient but, if shortened, would be a burden.

2. If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

   Incorrect Definition: GCIR should observe the practice of multiple LSEs aggregating and agreeing with other entities such as ISOs to determine such requirements. The GCIR for grouped LSEs would differ from the sum of the individual LSEs. In such a case CBM will be determined for the aggregate and processes/ procedures for individual LSEs to request CBM will not be observed.

3. If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

   Incorrect Requirement: The requirements in MOD 1 to meet the update periods are not required to meet the reliability aspects of ATC implementation.

   MOD 4:

   PJM disagrees with the essence of the proposed Mod 4-CBM standard. As currently constructed, the requirements treat CBM as if it is an energy quantity as opposed to a reliability margin. The proposed standard reads more like a procedure manual applicable to a single vertically integrated utility. The majority of load served in the US does not use the CBM as a product construct. PJM will suggest modifications that will better reflect CBM as a margin, not a commercial product, used to preserve the reliability of multiple LSE's through various reliability agreements. The suggested changes will preserve the ability of a single LSE to treat CBM as a product, but will refocus the discussion to better articulate the concepts used in a market environment.

   Provisions need to be made to allow the flexibility of LSEs to agregate and allow the planning to be handled by an ISO. There are conflicts with the PJM Reliability Assurance Agreement Amongst Load Serving Entities.

   The GCIR definition recognizes the aggregation of LSEs and the requirements in MOD 4 do not. For example R1.1 specifies LSE as a single entity. The requirements do not provide for other methods of managing CBM both in planning and operationally. It is recognized that multiple LSEs may aggregate but the procedural requirements of R3 for instance are on a LSE specific basis. The standards must recognize FERC accepted practices for instance the definition and methods of addressing GCIR should recognize that the net CBM for an aggregate of LSEs may be less than the sum of the CBM needed for each LSE.

GCIR definition should recognize that the net CBM for an aggregate of LSEs may be less than the sum of the CBM needed for each LSE.

If these standards are to be as procedural/process specific as they are now written then alternate applications of CBM are necessary. Some examples include but are not limited to:

R1.1 The drafting team would need to add language to recognize processes such as PJM's IRM study as satisfying requirements to determine import requirements. For the group of LSE's with an aggregated need for CBM.

Language must be changed in the standard allowing flexibility to LSEs and Balance Authorities to apply different methods and procedures for instance:

R1.3 Remove the words "for a Load Serving Entity to request" would allow other entities or agents to act on behalf of LSEs.

R3 through R10 contain timeframes that would not apply when CBM is determined on differing intervals. This standard is too specific to processes implemented in specific regions. The GCIR and CBM may not change on these intervals and these requirements would be inappropriate. These requirements do not recognize the practice implemented by groups of LSEs acting through a stakeholder process in the determination of area wide CBM and reserve margins.

MOD - 008

R1.3 The TRM allocation method may include a process contained in the AFC or ATC calculator that overrides the base TRM value.

R1.6 There is a need to implement a requirement for cases where the TRM applied differs from the calculation. Such a number should be provided to the RC with sufficient documentation for the RC to approve the TRM prior to implementation. These instances should be documented in the TRMID.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:
Violation Severity Levels

NERC Standards should be developed to assure reliability. Standard business practices related to fair market practices should be developed and implemented by NAESB.

PJM supports the IRC comment that in order for "requirements to have a medium VRF, according to the VRF criteria in Drafting Team Guidelines, they would have to directly affect the electrical state or capability of the bulk electric system or ability to effectively monitor and control the bulk electric system or in the planning time frame, or if violated, could under emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of capability of the bulk electric system."

Further, a Violation Severity Level should be a measure of the potential impact to reliability. If a violation does not impact reliability, there should not be a VSL assigned at all.

PJM agrees with SERC comments that violation levels for TFC should only be moderate or higher if they exceed an SOL or IROL.

The VSLs set in the MOD standards are not consistent with the definitions the VSL definition in the Violation Severity Limit Definitions Table in Figure 1 of "Violation Severity Levels Development Guidelines Criteria October 10, 2007" (VSL Guidelines). The definition in the VSL Guidelines defines a Moderate Violation (VSL 2) as "non-compliant with respect to one significant element within the requirement." For example, MOD-030-1 sets the Severe VSL for R3 as "The Transmission Operator did not update the Transmission model per the schedule specified in R3," which is based on a violation of a single significant element. This clearly falls under the definition of a moderate VSL per the VSL Guidelines. The entire set of Violation Severity Levels in the MOD standards needs to be revised per the VSL Guidelines.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☒ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments: The requirements are procedural in nature and conflict with PJM's implementation of ATC and CBM. The LSEs have delegated authority to implement CBM and determine reserve margins to PJM in the RAA. The PJM membership have enjoyed the benefits of an area wide application of CBM. The standards specify requirements that do not observe differing implementations of CBM. The procedural requirements of the standards conflict with the procedures in PJM Manuals and implemented by PJM In the RAA, and JOAs. These standards additionally would then affect the ability for LSEs to delegate responsibility to ISOs by limiting both the general flexibility by which CBM may be implemented and the specific application in PJM.

The standards must state that the requirements do not apply in the event that the responsible parties have FERC approved aggreements in place that differ in implementation. Such agreements may include the RAA, and JOAs between ISOs.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: PJM encourages further development that would include a diversity of implementations. PJM also wishes a clear distinction between reliability aspects and economic aspects in further revisions

MOD-001 Available Transfer Capability

R3.2 - Is this requirement consistent with use of the terms "counter flow" and "counter reservation" in the rest of the Standard?

R3.6 - What is the definition of "Allocation methodologies" and is it different for flowgate capabilities or paths?

R9: We believe the frequency could be better addressed and aligned with other posting requirements by NAESB in business practices.

R10: Insert "its own data" in the first sentence, 3rd line as follows: …Provider shall begin to make "its own data" available on the schedule specified…

MOD-004 Capacity Benefit Margin

R2: The acronym "CBID" in the 2nd line of the first sentence should be "CBMID". Entities should have a more reasonable time frame of fourteen (14) calendar days to make CBMID and any changes available to applicable parties.

R6 - Fourteen (14) calendar days for providing requested CBM information would be more reasonable.

R7.1 and R7.2 - Fourteen calendar days for providing CBM supporting data would be more reasonable.

R9: Add "within the bounds of reliable operation" to the end of the R9 requirement description.

MOD-008 TRM Calculation Methodology

R3, R4, R5 - Fourteen calendar days for providing TRM calculations and supporting data would be more reasonable.

MOD-030 Flowgate Methodology

R2.1.1 - The current definition makes every facility a flowgate. Suggest changing the wording as follows, "Any facility within the Transmission Operator's area based on thermal, stability or voltage limits is eligible to become a flowgate." The requirements that follow (R2.1.2 and R2.1.3) would be sub-requirements of R2.1.1 that would be used to determine the subset of all transmission facilities described in R2.1.1 that become flowgates.

R2.1.2.1 - "This requirement is only applicable if the planning studies and operating studies use the same methodologies. If the planning studies use a TTC methodology then all transmission facilities may be contingencies. In AFC studies only the select flowgate definitions that contain contingency elements would be included. Recommend removing this requirement." If this requirement remains suggest following wording, …Use Contingencies consistent with the Contingencies used in operations studies and planning studies for the applicable time", but not all contingencies used in studies need to be included in transfer analyses."

R2.2 - Should be yearly instead of quarterly. Delete the word "definitions" from the sentence.

R3.1 - Recommend that R3.1 be deleted since TFC may be derived from another source such as a flowgate parameter files. This is should be an acceptable practice since it is easier to maintain flowgate attributes/parameters in files included in the calculation process than in the load flow models.

R3.4 and R3.5 - Change Reliability Coordinator's area to Transmission Operator's area.

R4.2 - What is the definition of an interface point? It is suggested that the words "the interface point with" should be clarified or revised from the language in bullet points 3,4,7 and 8 under R4.2.

R5.1 - Recommend rewording of R5.1 to address outage rules. Outage rules used in the standard to define the set of outages to include in monthly or daily calculations where multiple outage periods exist. An example would be that in monthly AFC calculations all outages for the month are not included. Only the set of outages that meet the outage rules (for example all EHV with a duration of greater than 7 days or all outages that occur on the 3rd Wed of the month,etc) The requirement should be reworded to say "all outages that meet the outage rules as specified in the ATCID".

R5.2 - Replace the existing wording and deleting word "any" with the following: "For external third party flowgates, PDF greater than 5% and passing coordination agreement study process, if applicable, use the AFC for each specific flowgate provided by that third party as the AFC for that flowgate, except where there is a mutually agreed temporary problem with that value."

R6.3 and R6.4 - The threshold values for calculating impacts should be consistent with the threshold values contained in MOD-028.

R7.2 and R7.4 - The threshold values for calculating impacts should be consistent with the threshold values contained in MOD-028.

R8 - What is a "postback" as defined by NAESB?

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
|---|---|
| Name: | Brett Koelsch |
| Organization: | Progress Energy, Carolinas |
| Telephone: | |
| E-mail: | brett.koelsch@pgnmail.com |

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- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

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- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☐ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

- Incorrect Requirement: MOD-28-1 R7, MOD-030-1 R2.1.3.1
- The distribution factor/impact value used in the analysis of ATC impacting calculations should be consistent in all related processes. The value used in the process to approve transmission service should provide at least as accurate/granular results as the TLR process that is used to relieve congestion. The current TLR process uses a 5% impact, but there is discussion of using a 3% impact for non-firm curtailments. The ATC processes should not use an impact/distribution factor above 3%.
- The 3% value is in MOD-004 -1 4.1.2.2, MOD-030-1 – R6.3, R6.4, R7.2, R7.4 and R10.
- A 5% value is used in MOD-028-1 R7, MOD-030-1 R2.1.3.1.

The 5% impact or distribution values used in the Standards should be changed to 3% to be consistent across processes and Standard requirements, and to support the TLR process.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** Public Service Commission of South Carolina

**Lead Contact:** Phil Riley

**Contact Organization:** Public Service Commission of South Carolina

**Contact Segment:** 9

**Contact Telephone:** 803-896-5154

**Contact E-mail:** philip.riley@psc.sc.gov

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mignon L. Clyburn | Public Service Commission of SC | SERC | 9 |
| Elizabeth B. "Lib" Fleming | Public Service Commission of SC | SERC | 9 |
| G. O'Neal Hamilton | Public Service Commission of SC | SERC | 9 |
| John E. "Butch" Howard | Public Service Commission of SC | SERC | 9 |
| Randy Mitchell | Public Service Commission of SC | SERC | 9 |
| C. Robert "Bob" Moseley | Public Service Commission of SC | SERC | 9 |
| David A. Wright | Public Service Commission of SC | SERC | 9 |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

> **MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.
>
> **MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.
>
> **MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.
>
> **MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.
>
> **MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.
>
> **MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

# Arrangement of Requirements within the Proposed Set of 'ATC' Standards

## MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

## Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If “Yes,” please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If “Yes,” please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: None.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| Name: | Robert Harshbarger | |
| Organization: | Puget Sound Energy | |
| Telephone: | 425-462-3348 | |
| E-mail: | robert.harshbarger@pse.com | |

| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
|---|---|---|
| ☐ ERCOT | ☒ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** n/a

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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- Identify Flowgates
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- Basic Flowgate calculations:
  - TFC
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☒ Yes

☐ No

If "Yes," please identify your concerns. Comments: The proposed effective date langauge is sufficient. As mentioned below, the drafting team should review the effect date langauge in all six MODs to ensure consistency.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: In MOD-001, Posted Path is included in defined terms. This is a duplication of "Posted path" in 18 CFR Part 37.6 (b)(1)(i). Suggest that throughout these MODs, replace the term Posted Path with "paths required to be posted" or "paths requiring posting" or "paths for which ATC is calculated".

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement: See comments below.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element: The use of the term "horizon" in the violation risk labels has caused some confusion because of its use in ATC horizons (different time periods for which ATC is calculated in a specific manner).

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☒ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments: Throughout, these standards assert that the calculation of ATC is a reliability matter. This is incorrect. ATC is a commercial product, a commodity that is offered by transmission service providers, sold to transmission customers, and sometimes traded amongst transmission customers. FERC requires jurisdictional transmission providers to calculate and post ATC. 18 CFR Part 37.6 contains the standards of ATC calculation and posting. It is not reasonable to be subject both to FERC enforcement of the CFRs and to NERC enforcement of these overlapping standards.

In the west, reliability is not impacted by the miscalculation, posting, or sale of ATC. Reliability is impacted when transactions are scheduled in a manner that causes flows to exceed a path's TTC. And ,as such, improper TTCs impact reliability. Failure to evaluate proposed transactions and their impacts to the transmission system impacts reliability. It is reasonable that NERC reliability standards cover the calculation of TTC, and some aspects of CBM and TRM.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: MOD-001-1, A., 3. the stated Purpose contains noble goals which are not required for reliable system operation but for viable commercial activity. Reliable system operations are impacted by incorrect TTC values and uncoordinated transaction scheduling activities.

MOD-001-1, A., 4. applicability, the Transmission Service Provides calculate ATC. Transmission Operators (in the near term) and Transmission Planners (in the longer term) calculate TTC.

MOD-001-1, B., R1, Transmission Operators calculate transfer capability (TTC) of facilities within its TO area. Transmission Planners calculate transfer capability (TTC) of facilities within their TP areas. Transmission Service Providers calculate ATC for those paths that they are required to, choose to, or are asked to post.

MOD-001-1, B., R2 is a good requirement, but for commercial reasons, not reliability reasons. Transmission customers need to have access to more "granular" ATC closer to real-time. Also, why were weekly ATC values not included?

MOD-001-1, B., R3 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability. This requirement to create a separate implementation document creates an undue burden on the industry - transmission customers will have two different documents to review, and transmission service providers will have two different documents to maintain.

MOD-001-1, B., R3 the term "Facility" is used several times in MOD-001-1. The NERC glossary says facility is "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)". In R3.3 the requirement to list the Transmission Operators and Planning Coordinators for every facility under the TSP's tariff is burdensome and does not have value. Hundreds of facilities make-up even small systems. R3.3 should say "for each path for which the Transmission Service Provider calculates ATC, list the corresponding Transmission Operator and Transmission Planner and Reliability Coordinator".

MOD-001-1, B., R3.6 "Allocation methodologies" – it is not clear to what this means? Perhaps the following: "For paths where multiple Transmission Service Providers share capacity or have rights, describe how the capacity is allocated among providers", or words to that effect.

MOD-001-1, B., R4 is not needed, it is already covered in R3.2. If the drafting team wants to keep it, please move it MOD-028, MOD-029, and MOD-030. Since R4 leaves it open to each TSP's choice and requires them to document it, perhaps as a suggestion, the requirement could be to have the TSP do as they say they do in their Attachment C. The requirement might be rewritten to say "the TSP utilizes counter schedule information in their firm ATC calculations as specified in their Attachment C." Then, if the TSP fails to document or to do as they say they do, this could be a violation of the requirement.

MOD-001-1, B., R5 is not needed, it is already covered in R3.2. If the drafting team wants to keep it, please move it MOD-028, MOD-029, and MOD-030. Since R4 leaves it open to each TSP's choice and requires them to document it, perhaps as a suggestion, the requirement could be to have the TSP do as they say they do in their Attachment C. The requirement might be rewritten to say "the TSP utilizes counter schedule information in their firm ATC calculations as specified in their Attachment C." Then, if the TSP fails to document or to do as they say they do, this could be a violation of the requirement.

MOD-001-1, B., R6 is not necessary. Revisions to Attachment C are to be filed and posted.

MOD-001-1, B., R7 Attachment C is already required to be posted (available) for any entity to review, subject to CEII concerns.

MOD-001-1, B., R8 does not read clearly. Perhaps the phrase "categories of data" could be used. As R8 reads now, it can be interpreted as requiring any restudy of TTC to include previously used data rather than data that is reflective of the conditions of the time period being studied. Perhaps the requirement was for data used in the determination of TTC should be the most accurate, up-to-date data available and should reflect the expected conditions of the period of time under study.

MOD-001-1, B., R9 is not a reliability concern. In addition, it is unduly burdensome. Current and accurate ATCs are a commercial concern. In addition, performing 168 hourly calculations every hour when neither TTC nor ETC has changed, benefits no one and is costly. The commercial requirement should be to require the recalculation of hourly ATC once a day and whenever either TTC or ETC changes for any period of time between this hour and the next 168 hours. Also, require the recalculation of daily ATC once a day for the next 30 days and whenever either TTC or ETC changes for any period of time between this hour and the next 31 days.

MOD-001-1, B., R10, this requirement for data sharing between reliability entities is a good concept. However, as currently worded, all the burden to supply data is incorrectly placed totally upon the TSP and not on the Transmission Operator or Transmission

Planner. Much of the data listed is critical for proper TTC calculation which the TSP may not have access to. The TSP calculates ATC based on upon TTC supplied by the Transmission Operator and/or Transmission Planner. This requirement does not specify how the request is made or how the response or provision of data is dated. The corresponding measurement, M9, implies that all data items requested will be supplied within 14 days, but requirement states that the TSP will begin to make available at the 14 day mark. In addition, change first sentence words "…days of a request of any Transmission…" to "…days of a request made by any Transmission…" to read more in-line with the intent. Additionally, the requirement borders on a run-on sentence. Suggest moving the list of allowable requesters from R10 to be a sub-requirement R10.xx. The list of data is not all inclusive, there may other information needed. By each item, list what entity would have that data – TSPs would have ATC and ETC information, operators and planners would power flow data, etc.

MOD-004-1, A., Capacity Benefit Margin is a use of the transmission system that is requested by a load serving entity. This standard contains requirements for the interactions between the LSE and the transmission provider. These requirements are largely commercial in nature and should be under NAESB development. Reliability standards concerning CBM should only require LSEs to acquire a minimum CBM to ensure service to load.

MOD-004-1, A., 6. Effective Date language is not but should be exactly the same for all six MOD draft standards.

MOD-004-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider's CBM methodology. This requirement to create a separate implementation document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and providers would have to maintain two different documents.

MOD-004-1, B., R2 is not necessary. Revisions to Attachment C are to be filed and posted (available) for any entity to review, subject to CEII concerns.

MOD-004-1, B., combine R3.3 language into R3.1.

MOD-004-1, B., R3.2 it seems more reasonable for the requirement to read "LSE shall review any active CBM requests at least every six months and submit updates as required."

MOD-004-1, B., R4 uses active verb "shall set….as follows:" but R4.1 says "Determine the amount of CBM…". To align the language a little better perhaps R4 should simply say "…the Transmission Service Provider shall:". In that way the TSP shall "determine" (R4.1), shall "set" (R4.2), shall "increase" (R4.3).

MOD-004-1, B., R4.3 contemplates the case where there is insufficient capacity to meet all the CBM requests on a particular path, but there is no discussion on allocation of limited capacity to the requests. Is NAESB working on this aspect? If not, is it a TSP's discretion to develop a CBM allocation methodology?

MOD-004-1, B., R8, R9, R10, M11, M12, M13 use of the terms "tag" or "Interchange Transaction Tag" which is inconsistent with NERC INT and NAESB CI BP standards where specific reference to "tag" or "e-Tag" has purposefully been avoided in those standards. The term Request For Interchange (RFI) refers to a collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink BA. Or the term Arranged Interchange refers to the state where the Interchange Authority has received the Interchange information (initial or revised) and has distributed that information for reliablity assessment. I believe that in these requirements, Arranged Interchange is the more appropriate langauge.

MOD-004-1, B., R10 requires, without exception, that all submitted Arranged Interchange using CBM must be approved. This would force TSPs to potentially approve malformed transactions possibily citing incorrect contract arrangements, incorrect connectivity, etc. Perhaps the requierment could state the TSP shall approve all valid requests to schedule CBM. The drafting team might consider requiring the TSP or other approval entities to supply a meaningful reason for denying a CBM schedule.

MOD-008-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider's TRM methodology. This requirement to create a separate implementation document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and TSPs two different documents to maintain.

MOD-008-1, B., R1.1 suggest modifying to read: "For each path or flowgate that ATC or AFC is calculated, describe how each of the following components of uncertainty are used in calculating TRM for each of the ATC time horizons (if not applicable, indicate as such):" The words "ATC time horizons" could be used to eliminate the need for R1.4.

MOD-008-1, B., R.3 what "request" is being referred to? Should it read "…seven calendar days of a request from:"? Or should "of a request" be removed as a typo?

MOD-008-1, B., it seems that R1, 2, and 5 could be merged together into a new R1 TRM calculation and documentation. R3 and 4 could merged together into a new R2 on TRM data sharing.

MOD-029-1 inclusion of the Rated System Path methodology is greatly needed and appreciated. The drafting team was wise in including it and should be thanked for their efforts.

MOD-029-1 suggest reordering R4 to be R1.

MOD-029-1 R1 (modeling requirements) should include the statement that the data listed below should relfect the expected conditions for the applicable time period.

MOD-029-1 delete R2.7 as it, in its current form, does not provide the entire paradigm contained in the WECC's Procedures For Regional Planning Project Review And Rating Transmission Facilities.

MOD-029-1 in R6, is the "non-firm capacity reserved for NITS" the same as Secondary Network Service (i.e., NN-6)?

MOD-029-1 in R7 & R8, what are "Postbacks"?  This term is not used in the west.

MOD-029-1 in R5, R6, R7, & R8, calculation of ETC and ATC are commercial concerns and should be addressed in business practice standards NAESB and enforced through FERC's adoption of those business practice standards into the CFR.

MOD-029-1 in R8 the requirement says we are to use the same formula for all horizons – this is incorrect.  For the real-time, same-day time frame, we release all unscheduled capacity as non-firm ATC.  As such, the formula would read:

ATCNF = TTC – Scheduled ETCF – Scheduled ETCNF – CBMS – TRMU + Counter-schedulesF + Counter-schedulesNF

MOD-030-1 it is unreasonable for TSPs to convert AFC values into ATC values simply because FERC regulations fail to contain the term AFC.  For large systems using this methodology, posting thousands of ATC values benefits no one if AFC values can give transmission customers a better picture of available capability of the transmission system.  It is recommended that TSPs using MOD-030-1 post AFCs and provide customers tools to either convert AFC information to specific POR-POD ATCs or tools which indicate the feasibility of a transaction from POR to POD.

Thank you for the opportunity to comment.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| Name: | Rod Noteboom | |
| Organization: | Public Utility District #2 of Grant County, Washington | |
| Telephone: | 509-766-2523 | |
| E-mail: | rnotebo@gcpud.org | |

| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
|---|---|---|
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
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- Converted descriptive language into algorithms for calculating ETC and ATC.
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## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
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    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

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The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

   ☐ Yes

   ☒ No

   If "Yes," please identify your concerns. Comments:

   We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

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   Comments:

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
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- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

### MOD-004<br>Capacity Benefit Margin<br>(CBM)

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

### MOD-008<br>Transmission Reliability Margin<br>(TRM)

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

## Choose One or More Methodologies

### MOD-028<br>Area Interchange Methodology

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

### MOD-029<br>Rated System Path Methodology

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
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Group Comments (Complete this page if comments are from a group.)

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**Lead Contact:** Terry Blackwell

**Contact Organization:** Santee Cooper

**Contact Segment:** Transmission

**Contact Telephone:** 843-761-8000 ext. 5196

**Contact E-mail:** tlblackw@santeecooper.com

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|---|---|---|---|
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| William Gaither | Santee Cooper | SERC | 1 |
| Art Brown | Santee Cooper | SERC | 1 |
| Vicky Budreau | Santee Cooper | SERC | 1 |
| Rene' Free | Santee Cooper | SERC | 1 |
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**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: Recommend changing Posted Path 1) definition to read "Any Balancing Authority to Balancing Authority direct interconnection". Add the word direct.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement: MOD028 R3.1 should read "For …, and next-day on-peak TTCs". Remove intra-peak after next day.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: MOD001 R3.3

Make sure that the data retention requirements are not more stringent than the FERC Requirements. Also, be consistent with the data retention requirements instead of having some that say most recent calendar year plus current year and some say three calendar years.

MOD004 Effective date should list the six standards consistent with all the other standard's effective date.

MOD004 R6 need to be consistent with wording.  It should either read "Within five business days" or "Within five calendar days".

MOD004 consider removing R8, R9, and R10 since these are related to Business Practices.

In MOD029 consider adding some detail requirements related to the ATCID similiar to details outlined in MOD028.

Real-time Planning, Operations Planning, and Long-term Planning should be defined in the NERC Glossary.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** SERC ATCWG - MOD-001, MOD-004, MOD-008, MOD-028 and MOD-030 Comments

**Lead Contact:** Doug Bailey

**Contact Organization:** Tennessee Valley Authority

**Contact Segment:** 1,3,5,9

**Contact Telephone:** 423-697-2906

**Contact E-mail:** dhbailey2@tva.gov

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Michael Toll | E.ON. U.S. | SERC | 1,3,5 |
| Helen Stines | APGI - Yadkin | SERC | 1,5 |
| Stan Shealy | South Carolina Electric & Gas | SERC | 1,3,5 |
| Ross Kovacs | Georgia Transmission Corp. | SERC | 1,3,5 |
| Phil Creech | Progress Energy - Carolinas | SERC | 1,3,5 |
| Eugene Warnecke | Ameren | SERC | 1,3,5 |
| Matt Burns | Big Rivers Electric Cooperative | SERC | 1,3,5 |
| Al McMeekin | South Carolina Electric & Gas | SERC | 1,3,5 |
| Don Reichenbach | Duke Energy - Carolinas | SERC | 1,3,5 |
| Kiet Nguyen | Associated Electric Cooperative, Inc | SERC | 1,3,5 |
| DuShaune Carter | Southern Company Transmission | SERC | 1,3,5 |
| Bryan Hill | Southern Company | SERC | 1,3,5 |
| Larry Rodriguez | Union Power Partners | SERC | 4,5 |
| Donald Williams | PJM | SERC | 1,2,3,5 |
| Larry Middleton | Midwest ISO | SERC | 1,2,3,5 |
| Jerry Tang | Municipal Electric Authority of GA | SERC | 1,3,5 |
| Joe Francois | Entergy | SERC | 1,3,5 |
| Laura Lee | Duke Energy Carolinas | SERC | 1,3,5 |
| Doug McLaughlin | Southern Co Transmission | SERC | 1,3,5 |
| John Troha | SERC Reliability Corporation | SERC | 10 |
| | | | |
| | | | |

*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

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The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

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- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

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The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments: This time alloted is sufficient but, if shortened, would be a burden.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: MOD-0028, 029 and 030 refer to "postback". There is not a definition in the NERC Glossary for this term. Please consider the following as the definition: "Postbacks are increases to ATC values resulting from transmission service being redirected by customers to other paths or from transmission service not being scheduled by customers during that period, as defined in Business Practices."

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement: MOD-028, Requirement R5 and MOD 030, Requirement R4, refer to the term "interface point" with the adjacent TSP. To meet this requirement, an entity must simulate an artificial source/sink at the interface point. It should utilize the adjacent TSP area as the source/sink.

TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL (which are defined in other standards, e.g., IRO-004-1 and IRO-005-1). Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1, and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL. The following Violation Risk Factors listed as Medium in the proposed MOD-028-1, MOD-029-1, and MOD-030-1 should be listed as Lower: MOD-028-1, R2; MOD-028-1, R3; MOD-028-1, R9; MOD-028-1, R11; MOD-029-1, R1; MOD-029-1, R2; MOD-029-1, R5; MOD-029-1, R7; MOD-030-1, R3; MOD-030-1, R5; MOD-030-1, R6; and MOD-030-1, R9. For clarity, the risk factor for each requirement is suggested below:

- In MOD-028-1, R2, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-028-1, R3, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-028-1, R9, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-028-1, R11, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-029-1, R1, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-029-1, R2, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-029-1, R5, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-029-1, R7, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-030-1, R2, the Violation Risk Factor is listed as Lower; it should be listed as Medium. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-030-1, R3, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-030-1, R5, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-030-1, R6, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

- In MOD-030-1, R9, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element: Revise MOD-028-1, M5 to the following: The transmission operator shall describe in its ATCID the requirement to allocate TTC and show that any allocations of TTC were respected as required in R5.2.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.

Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

MOD-001 Available Transfer Capability

R3.1 - Is this requirement consistent with use of the terms "counter flow" and "counter reservation" in the rest of the Standard?

R3.6 - What is the definition of "Allocation" of flow gate capabilities or paths

R9: Is this consistent with communications protocols and NAESB Business Practices? In addition, it shouldn't be necessary to update a value that hasn't changed.

R10: Insert "its own data" in the first sentence, 3rd line as follows: …Provider shall begin to make "its own data" available on the schedule specified… Fourteen (14) days appears to be unreasonably burdensome to supply the significant amount of data contemplated - thirty (30) days would be a more reasonable time period we would support. In addition, an entity should not be required to supply another entity's data that is used in their models.

R10.8 - This requirement needs clarification. Why isn't it covered by the rules of counterflow? If not, it should be explained why it isn't or removed from the standard. It seems to fall in and be a part of the TRM standard.

R10.13 - In an AFC environment, there should not be a requirement to post CBM and TRM on a Posted Path.

R10-13 and R10.14 - It appears that R10.13 and R10.14 should be combined under one Requirement as sections "a" and "b". R10.13 applies to Rated system Path and R10.14 applies to AFC. There should also be a measure that applies to the top level.

MOD-004 Capacity Benefit Margin

R2: The acronym "CBID" in the 2nd line of the first sentence should be "CBMID". Entities should have a more reasonable time frame of fourteen (14) calendar days to make CBMID and any changes available to applicable partiesRequirement 4:

R4.1.2.2 - Entities should have the option to use a lower threshhold than 3%, if desired.

R6 - Fourteen (14) calendar days for providing requested CBM information would be more reasonable.

R7.1 and R7.2 - Fourteen calendar days for providing CBM supporting data would be more reasonable.

R9: Add "within the bounds of reliable operation" to the end of the R9 requirement description.

MOD-008 TRM Calculation Methodology

R3, R4, R5 - Fourteen calendar days for providing TRM calculations and supporting data would be more reasonable.

MOD-028 Area Interchange Methdology

The existing wording for R3 (and R4) is very difficult to follow. Also, it appears that the drafting team intends that a peak and an off-peak TTC value will be calculated each day. Please consider using wording such as the following to add clarity:

R3 - When calculating TTC values (for intra-day and next day) for Posted Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's Area. The Transmission Operator shall also include comparable data associated with external Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers, and by any other Transmission Service Providers with which coordination agreements have been executed. The Transmission Operator shall include (at a minimum):

R3.1. Expected generation and Transmission outages, additions, and retirements.

R3.2. Load forecasts for the on-peak periods and the off-peak periods being calculated. At a minimum, a peak value and an off-peak value shall be calculated for each day.

R3.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R4 - Wording similar to R3 can be used in R4 (as shown below). Alternately, R4 could simply be combined into R3 by changing "(for intra-day and next day)" in the first sentence to "(for intra-day through Month 13.)"

R4. When calculating TTC values (for time periods beyond next day) for Posted Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's Area. The Transmission Operator shall also include comparable data associated with external Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers, and by any other Transmission Service Providers with which coordination agreements have been executed. The Transmission Operator shall include (at a minimum):

R4.1. Expected generation and Transmission outages, additions, and retirements.

R4.2. Peak Load forecasts for the periods being calculated.

R4.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R5.3 - What is the definition of an interface point? This would require artificially modeling a generator as a source or sink. It is suggested that the words "the interface point with" should be deleted from the language in bullet points 3,4,7 and 8 under R5.3.

R11 and R12 - What is a "postback" as defined by NAESB?

MOD-030 Flowgate Methodology

R2.1.1 - The current definition makes every facility a flowgate. Suggest changing the wording as follows, "Any facility within the Transmission Operator's area based on thermal, stability or voltage limits is eligible to become a flowgate." The requirements that follow (R2.1.2 and R2.1.3) would be sub-requirements of R2.1.1 that would be used to determine the subset of all transmission facilities described in R2.1.1 that become flowgates.

R2.1.2.1 - This requirement is only applicable if the planning studies and operating studies use the same methodologies. If the planning studies use a TTC methodology then all transmission facilities may be contingencies. In AFC studies only the select flowgate definitions that contain contingency elements would be included. Recommend removing this requirement.

R2.2 - Should be yearly instead of quarterly. Delete the word "definitions" from the sentence.

R3.1 - Recommend that R3.1 be deleted since TFC may be derived from another source such as a subsystem file. This is a common industry practice since it is easier to maintain flowgate attributes in external subystem files than in the load flow models.

R3.4 and R3.5 - Change Reliability Coordinator's area to Transmission Operator's area.

R4.2 - What is the definition of an interface point? This would require artificially modeling a generator as a source or sink. It is suggested that the words "the interface point with" should be deleted from the language in bullet points 3,4,7 and 8 under R4.2.

R5.1 - Recommend rewording of R5.1 to address outage rules. Outage rules are used in to define the set of outages to include in monthly or daily calculations where multiple outage periods exist. An example would be that in monthly AFC calculations all outages for the month are not included. Only the set of outages that meet the outage rules (i.e. all EHV with a duration of greater than 7 days or all outages that occur on the 3rd Wed of the month,etc) The requirement should be reworded to say "all outages that meet the outage rules as specified in the ATCID".

R5.2 - Replace the existing wording with the following: "For external third party flowgates and PDF grreater than 5%, Use the AFC for each specific flowgate provided by that third partyas the AFC for that flowgate."

R6.3 and R6.4 - The threshhold values for calculating impacts should be consistent with the threshhold values contained in MOD-028.

R7.2 and R7.4 - The threshhold values for calculating impacts should be consistent with the threshhold values contained in MOD-028.

R8 - What is a "postback" as defined by NAESB?

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Jay Campbell | | |
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| Telephone: 775-834-3782 | | |
| E-mail: jcampbell@sppc.com | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

> **MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.
>
> **MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.
>
> **MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.
>
> **MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.
>
> **MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.
>
> **MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments: NEVP and SPPC, the SPR companies, strongly support the inclusion of a 12 month implementation period for these standards. Particularly for MOD-29, the standard as drafted will require that numerous paths not previously exposed to the high rigors of the MOD-29 TTC determination process will have to be examined. Entities such as NEVP and SPPC electing the Rated System Path Methodology will require this period to assure proper review of the Posted Paths under their perview. Should a shorter period be mandated, it is highly likely that entities electing the Rated System Path Methodology will be in non-compliance as of any implementation date short of the full 12 months recommended.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: MOD-001 "Posted Path" is included in defined terms. Because this is a duplication of "Posted Path" in 18 CFR Part 37.6 (b)(1)(i) it is suggested "paths where ATC is calculated" or similar definition be used. "Counterflows" appears to be used interchangeably to mean actual flows of energy, scheduling of energy or reservations of transmission for possible scheduling of energy. The SPR Companies suggest the NERC ATC Drafting Team clarify the meaning of the term as well as how it integrates into each proposed standard. Specifically, the NERC Team should clarify such items as: 1) is it a flow, a schedule or a reservation, 2) does it change characteristics based on the time frame examined (E.g. is it a reservation before it becomes a schedule?), 3) is it uni-directional or bi-directional. The term is used in numerous calculations but as presented is too vague to calculate in the formula.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement: (All standards should be checked for consistency in the use of the terms "calendar days" and "days." In addition, these terms may differ between the Requirements and the corresponding VSLs. E.g. MOD-4, R4 specifies "calendar days" whereas the VSL for this requirement stipulates "days."

MOD-001 -

R1. and R2

States "…for each Posted Path per time period…" and "…values for the time periods listed…" respectively. The terms "time period" should be changed to "time horizon."

This locks the time window to a prescribed window and negates the ability to assign a random "time period."

The use of the term "horizon" as used with the Violation Risk Factors is confusing becaues of the way "horizon" is used to calculate ATC. Always qualifying the horizon with ATC Horizon or VRF Time Horizon would help clarify the way this term is used.

R3.3.

This requirement needs to be broken into to different requirements and a change to the term Facility needs to be made as follows:

- • (New) R3.3 "The identity of the Planning Coordinator responsible for assessing the long term reliability of each path where ATC is calculated under the Transmission Provider's tariff."

• (New) R3.X "The identity of the Transmission Operator responsible for the real time operating reliability of each path where ATC is calculated under the Transmission Provider's tariff."

R3.6.

• The format of this sub-requirement does not match that of the other five sub-requirements ahead of it making the meaning unclear. Suggest the following:

- • "R3.6. A description of the methodology(ies) used to allocate ATC among multiple lines or sub-paths within a larger Posted Path, including where applicable, any methodology(ies) used to allocate ATC among multiple owners of a single path."

• R4 and R5. "Counterflows" Requirements

R4 and R5 should be cut and counterflows should be addressed as subcomponents in MOD-028, R11 AND R12; MOD-029, R7 and R8; MOD-030, R8 and R9. Counterflows should be pasted into the MOD-028, MOD-029 and MOD-030 as the last element of requirements.

R6 E-Mail requirement when ATCID, TRMID, or CBMID are made

Recommend this be sent to NAESB to develop a place on OASIS for posting when changes are made.

R9 - "Update ATC"

Recommend R9 be removed and let NAESB handle ATC updates/postings in the NAESB standards. If not removed, ATC should only need to be reviewed and updated if necessary. Change wording to "shall review and update if necessary…"

R10. Making Requested Data Available

Needs to be reworded and clearly state only data that already exists can be requested or must be provided and should have points broken down into sub requirements. Suggested rewording:

- • "R10. Upon request from another Transmission Service Provider, Planning Coordinator or Reliability Coordinator, each Transmission Service Provider shall only provide requested data from the specificied list below, and only that data already in existence and in the possession of the Transmission Service Provider. Provision of all data is subject to confidentiality and security requirements. Each Transmission Service Provider providing information pursuant R10 shall do so:
- • RXX.1 Within fourteen days of a request
- • RXX.2 On the interval specified by the requesting entity, not to exceed more frequently than once per hour unless mutually agreed upon by the requestor and provider.
- • RXX.3 In the format in which the data exists at the time of the request, unless otherwise agreed upon by the requestor and provider.

    - Rxx.4 For the requested time period up to 13 months in the future."

R10.4. List of Data Elements that can be requested for NITS is too vague. Recommend changing to:

(New) R10.4 "Network Integration Transmission Service capacity on an aggregated basis."

R10.13.

- There is a stray right parenthesis after the word "Margin."

MOD-004 -

R1.3. Scheduling Over CBM

states that the Transmission Provider shall have a procedure that would allow a Load-Serving Entity (LSE) to request and schedule energy over (could be taken as in excess of the amount) that it has set-a-side for CBM. This requirement would be inconsistent and contradictory with the requirements that R3 has placed on the LSE with regards to the information that an LSE must provide prior to CBM being evaluated and set-a-side by the Transmission Provider if interpreted as such. Therefore a LSE should never be allowed to schedule energy over the amount of Transfer Capability set aside as CBM and suggest "over" to be changed to "on".

- • R2 CBMID Availability

    - The acronym "CBID" should be changed to "CBMID."

Requires a seven day turnaround time on providing the CBMID or other related information to requesting parties. We suggest a 14 day time period in which to allow the Transmission Provider to supply such information to requesting parties.

R3 LSE Requirements for Requesting CBM

Describes the requirements placed on the LSE that is requesting CBM. In being consistent with the rest of the MOD there needs to be specific timelines that the LSE must adhere to if there application is deemed insufficient and requires the LSE to submit additional information to the Transmission Provider. We suggest a 14 day requirement, or clarification that if an LSE's application is deemed insufficient it shall be immediately rejected and the LSE shall be removed from the que.

- R4.3.
- States that if during an evaluation of monthly ATC, additional firm capacity becomes available, the capacity shall be granted to CBM customers first. This requirement would appear to give CBM a preferential que position over Conditional Firm, which appears to be a stark contrast to the requirements set forth in FERC Order 890 with regards to Conditional Firm que position and the availabilty of new monthly firm ATC.
- R6 and Measure M9
- Both give the Transmission Provider only five days to provide information to requesting parties, we recommend both sections be changed to ten business days or 14 calendar days.

R7.1. and R7.2.

Refer to seven calendar days, we suggest that both requirements be changed to fourteen calendar days.

MOD-029 -

R1.6.

• Suggest this bullet be deleted. This is already addressed in R2 wherein the modeling process is dictated. Please note in the Rated System Path methodology, "peak load forecasts" are not used to stress the system; rather, load and generation are simulated to stress the system to its greatest capacity. There are cases when the highest forecasted load may not stress the system to its greatest utilization – which is the goal of the R2 under the Rated System Path.

R2

The performance criteria defined in R2 might, at some point be at odds with the proposed TPL standard. While the drafting team may not want to have references to another standard, the risk in not doing so would be that either standard would get modified an possibly create a contradiction that could be impossible to meet. Hence, MOD-029-1 should reference TPL for purposes of performance criteria.

R2.1.3.

Seems to contradict R2.1.2 regarding the facility ratings clause. All of R2.1 concerns n-0, 1 & 2 outages. R2.1.1 specifically refers to n-0 outates and R2.1.2 with n-1 & 2 outages. Further, R.2.1.2 requires "no Transmission Element modeled above its emergency rating" following an outage; R.2.1.1 requires no"Transmission Element above 100% of its continuous rating" for n-0. Then along comes R2.1.3 which basically says no element above its rating ever! I suggest striking R2.1.3. It's contradictory and excessive.

- • R2.3
- • Suggest correcting "…as determined by R1.2.1…" to read "…as determined by R2.1."
- R2.1.5.
- stating that a three-phase fault should be modeled on "all" busses could imply simultaneous faults at every point around a path. The intent is one fault at a time, on all surrounding busses. Replacing "all" with "each" would make the intent clear.
- • R5.
- • The language describing Native Load should be changed from "reserved" to "allocated." Allocated is the word most frequently used in conjunction with OASIS to describe this condition. The same change should apply to GF sub F.

  • The language describing Grandfathered capacity includes the defined terms "Firm" and "Transmission Service." Use of these words as defined terms is inconsistent throughout the proposed standards. They should either be changed here to a lower case or all applicable areas in each proposed standard should be changed to the defined term.

  MOD-030 -
- An entity using both MOD-030 for some paths and MOD-029 for other paths that are adjacent to entities using MOD-029 need not study Flowgates beyond the intersecting cut plane of its interface as the ATC at the interface does not fall under MOD-30 but MOD-29. To prevent seams issues and unnecessary analysis the Team suggests the following rewrite(s):
- • MOD-30, R2.1.2. All first Contingency transfer analyses from all adjacent Balancing Authority source/sink combinations either: a) to at least the first three limiting Elements / Contingency combinations within the Transmission Operator's system or b) to the interface of the adjacent Balancing Authority where the Transmission Operator utilizes the Rated System Path methodolgy whichever is applicable.
- •
- • If adopted, this same concept would be applied to: MOD-30, R3.5, R3.6, R5.1, R7.2 and R7.4.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element: The SPR companies are in support of lowering the Violation Risk Factors and Violation Severity Levels as specifically commented on by SERC. At best all Violation Risk Factors should be LOW, as none of these requirements pose risk to the reliability of the interconnected Bulk Electric System, and are only commercial in nature. (Please refer to the response to Q5 below regarding the lack of applicability of these Standards to the reliability of the BES.)
Specific:

MOD-01

M9
There is an unnecessary word "the" following the word "show" in the second line of the measure.

VSL for R4.
The word "Firm" should be inserted before the word ATC as R4 only refers to Firm ATC.

VSL for R5.
The word "Non-Firm" should be inserted before the word ATC as R5 only refers to Non-Firm ATC.

MOD-04

M1
Suggested rewording: "Each Transmission Service Provider shall produce its CBMID evidencing inclusion of all specified information in R1."
This approach should also be taken at M1 for MOD-08.

M5
M5, line 3 states "…they it has based its CBM…" Please change to "…that it has based its CBM…"

VSL for R2
The acronym "CBID" should be changed to "CBMID."

VSL for R10
The VSL is unclear. We suggest that it be rewritten to state, "The Transmission Service Provider failed to approve an Interchange Transaction Tag for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available."

D1.3 Data Retention
For clarity and consistency, the phrase "three calendar years" in the second through fifth bullets should be changed to "most recent three calendar years plus the current year."

MOD-08

M5
M5 is missing the right parenthesis after the word "data" on the first line.

VSL for R1
In the Moderate Level column, change the phrase "changes been" to "changes that have been".

MOD-29

M1.
M1 inaccurately calls for production of "models" used to derive TTC. As there are multiple conditions under MOD-29, R2 where a model does not dictate the predicate for TTC, M1 should be reworded to state "…shall produce the models, contracts, nomograms, reports or study results…"

Corresponding to:
1) Models in R2.1, R2.2. and R2.5;
2) Contracts in R.2.3 and R2.6;
3) Nomograms in R2.4;
4) Reports or studies in R2.7 and R2.8.

M1.3
The Team suggests correcting M1.3 from "…as stated in R1.1 through R.12…" to "…as stated in R1.1 through R1.12…"

M4.
If "M1" above is adopted, M4 is duplicative of M1 and should be deleted.

VSL for R4.
An SOL does not exist for every Posted Path. This VSL should be amended by changing the words "the SOL" in the High and Severe columns to read "any SOL". This makes the wording of the Requirement consistent with the wording of the Measure.

VSL R5, R6, R7, R8
These VRFs call for only a "severe" determination. They also mandate that the TSP "use" all the elements defined. However, the TSP will not "use" all the defined elements if they are not applicable. Thus, if a TSP does not "use" all elements defined because all the elements were not applicable – the TSP is in violation for not including null elements in its calcuation.

The SPR companies suggest these be rewritten to state: "The Transmission Service Provider did not use all affected elements as defined in…." This approach should help clarify that "zero" as an integer is an acceptable entry and that only those variables "affected" need be reported or acted upon.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☒ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments: Throughout, these standards assert that the calculation of ATC is a reliability matter. This is incorrect. ATC is a commercial product, a commodity that is offered by transmission service providers, sold to transmission customers, and sometimes traded amongst transmission customers. FERC requires jurisdictional transmission providers to calculate and post ATC. 18 CFR Part 37.6 contains the standards of ATC calculation and posting. It is not reasonable to be subject both to FERC enforcement of the CFRs and to NERC enforcement of these overlapping standards.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

In MOD-001, not one Requirement should have a VRF other than Lower. Certainly for the Rated System Path Methodology, not calculating ATC means not posting ATC, means not selling Transmission, means not allowing any flow. No flow is less reliable (i.e., greater risk?) than some flow? No. While it is certainly important to have transparency in the ATC methodology, including ATC/TTC calculations, a VRF of Medum is excessive. Having an incorrect ATC value 13 months in the future is in no way materially affecting reliability.

GENERAL

1) The SPR companies support retention of the three methods recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028).

2) The SPR companies strongly support the retention of the proposed one-year implementation period.

3) The SPR companies support allowing NAESB to address all "posting" issues as they directly affect OASIS and any reference to postings shold be removed.

MOD-001 Umbrella

1) The SPR companies support allowing the use of more than one methodology for calculation of ATC by any one entity. For example, the SPR companies support allowing any entity to use the Flowgate methodology inside their affected area while also using the Rated System Path methodology at its boundaries.

2) The SPR companies support allowing each entity to specify in its ATCID how it will treat counterflows / schedules. (R4., R5.) within the methodology each entity chooses. This will allow the entity to use counter schedules instead of counterflows where applicable.

3) The SPR companies support the aggregation of transmission capacity for grandfathered contracts when shared with neighboring requestors.

4) The SPR companies support the specifically limited universe of entities to which data sharing is required as prescribed in R10.

5) The SPR companies support those comments submitted by SERC specifying suggested changes to the VRFs. However, this Team makes no comment on the VRFs as they affect MOD-28.

MOD-029 RATED SYSTEM PATH TTC, ETC & ATC

1) The SPR companies support retention of the requirement(s) in R2.2 that accommodate paths which are “flow limited” by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing practices without re-inventing the wheel where no such effort is required to meet FERC’s goals of transparency and consistency.

2) The SPR companies support retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.

3) The SPR companies support retention of the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.

4) The SPR companies support retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts, associated litigation and potential renegotiation of associated operational agreements while supporting FERC’s mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation metholdogies is required.

5) The SPR companies support the adoption of a definition for counterflow to clarify its application in each equation."

MOD-004 CBM

1) The SPR companies support the concept of allowing the LSE to decide how much CBM it needs to satisfy its resource adequacy requirements and the TSP determining how the total CBM requirement for all requesting LSE’s is allocated among paths. This is the proper division of labor.

2) The SPR companies support allowing the LSE scheduling rights to the CBM after declaration of an EEA2 or higher condition.

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RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Linda Finley | | |
| Organization: Snohomish PUD | | |
| Telephone: 425 783 1990 | | |
| E-mail: lafinley@snopud.com | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☒ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values.** To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values.** Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values.** Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin.** Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values.** Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments: This allotted time is sufficient and if shortened, would be a burden, especially for those entities electing to use the Rated System Path methodology that will require a much more rigorous TTC determination process than has historically been used.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

MOD -001

R3.2 – "counter-schedules" should be deleted and "counterflows" should be capitalized with the definition supplied above [Counterflow: the impact of schedules, reservations, or actual energy flows in the direction opposite to the constraint

R3.3 – We agree with BPA about removal of this requirement, as it would require extensive modification to existing databases without serving a great need.

In addition we support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☒ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments: Throughout, these standards assert that the calculation of ATC is a reliability matter. This is incorrect. ATC is a commercial product, a commodity that is offered by transmission service providers, sold to transmission customers, and sometimes traded amongst transmission customers. FERC requires jurisdictional transmission providers to calculate and post ATC. 18 CFR Part 37.6 contains the standards of ATC calculation and posting. It is not reasonable to be subject both to FERC enforcement of the CFRs and to NERC enforcement of these overlapping standards.

In the West, reliability is not impacted by the miscalculation, posting, or sale of ATC. It is when transactions are scheduled that reliability is potentially impacted. Improper TTCs impact reliability. Failure to evaluate proposed transactions and their impacts to the transmission system impact reliability. It is reasonable that NERC reliability standards cover the calculation of TTC, and some aspects of CBM and TRM.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

2) MOD-030-1

R10 states that the TSP shall convert Flowgate AFCs to ATC for Posted Paths. Snohomish, as a major BPA customer, has a concern that if AFCs must be converted to ATCs for any possible constrainted POR/POD combination then conducting with our transmission provider will become very difficult. This would not have the effect that the Commission wanted as far as transparency. The explosion of data from ten flow gates to thousands of POR/POD's on the OASIS site will make it difficult to do business. BPA already provides its' customers with an easy to use tools to calculated the impact a request has on a flow gate.

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<table>
<tr><th colspan="3">Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)</th></tr>
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<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment<br>(check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☐ NPCC<br>☐ RFC<br>☒ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
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</table>

Group Comments (Complete this page if comments are from a group.)

**Group Name:** Southern Company Transmission

**Lead Contact:** Jim Busbin

**Contact Organization:** Southern Company Services, Inc.

**Contact Segment:** 1

**Contact Telephone:** 205-257-6357

**Contact E-mail:** jybusbin@southernco.com

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| DuShaune Carter | Southern Company Transmision | SERC | 1 |
| Doug McLaughlin | Southern Company Transmision | SERC | 1 |
| Marc Butts | Southern Company Transmision | SERC | 1 |
| J T Wood | Southern Company Transmision | SERC | 1 |
| Roman Carter | Southern Company Transmision | SERC | 1 |
| Jim Viikinsalo | Southern Company Transmision | SERC | 1 |
| Ron Carlsen | Southern Company Transmision | SERC | 1 |
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- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
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- Calculate TRM
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- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
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- Modeling requirements
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    - ATC (firm and non-firm)
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

MOD-028-1.

Suggest adding the following language to the end of the "Area Interchange Methodology" definition: "Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis, as opposed to being based upon a specific Transmission Path." Please see 1995 TTC Reference Document Reporting of transfer Cability on pages A-6.

MOD-029-1.

Suggest adding the following language to the end of the "Rated System Path Methodology" definition: "Under the Rated System Path Methodology, TTC results are reported with a focus toward specific transmission path capabilities." Please see 1995 TTC Reference Document Reporting of transfer Cability on pages A-7.

MOD-030.

TFC is generally based upon ratings, not SOL. Suggest the following language.

Total Flowgate Capability (TFC): The maximum flow capability on a Flowgate, not to exceed its thermal rating, or in the case of a proxy flowgate used to represent a specific operating constraint (such as a stability limit), not to exceed the associated System Operating Limit.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect,

please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element: MOD-028 M5 is inappropriate. There is no reliability need to provide copies of contracts which may in themselves be difficult to interpret. R1.3 should be changed to read as follows. "Any provisions for calculating allocations of TTC." M5 should be changed to read as follows. "The Transmission Service Providers's ATCID includes provisions for the allocation of TTC."

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

MOD-001 Comments:

R10. The language "any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator, each Transmission Service Provider shall begin to make available on the schedule specified by the requester (but no more frequently than once per hour" is too broad. "Any" provider, operator,etc. does not have reliability need for this information on an hourly basis. Much of the information does not change on an hourly basis. Please consider rewording as follows.

Proposed wording: any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator having a reliability need, each Transmission Service Provider shall begin to make available on a schedule mutually agreed to by the requester and the provider.

MOD-028 Comments:

R3. The existing wording for R3 (and R4) is very difficult to follow. Also, it appears that the drafting team intends that a peak and an off-peak TTC value will be calculated each day. Please consider using wording such as the following to add clarity.

Proposed wording: R3. When calculating TTC values (for intra-day and next day) for Posted Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's Area. The Transmission Operator shall also include comparable data associated with external Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers, and by any other Transmission Service Providers with which coordination agreements have been executed. The Transmission Operator shall include (at a minimum):

R3.1. Expected generation and Transmission outages, additions, and retirements.

R3.2. Load forecasts for the on-peak periods and the off-peak periods being calculated. At a minimum, a peak value and an off-peak value shall be calculated for each day.

R3.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R4. Wording similar to R3 can be used in R4 (as shown below). Alternately, R4 could simply be combined into R3 by changing "(for intra-day and next day)" in the first sentence to "(for intra-day through Month 13.)"

Proposed wording: R4. When calculating TTC values (for time periods beyond next day) for Posted Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's Area. The Transmission Operator shall also include comparable data associated with external Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers, and by any other Transmission Service Providers with which coordination agreements have been executed. The Transmission Operator shall include (at a minimum):

R4.1. Expected generation and Transmission outages, additions, and retirements.

R4.2. Peak Load forecasts for the periods being calculated.

R4.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

R5.3. R5 appears to apply to all TTC calculations, however R5.3 appears to be specific to monthly analysis; "the expected schedules using monthly or longer firm Transmission service". Please consider using the same wording as used in MOD-30 R4.

Proposed wording: When calculating TTCs for Posted Paths, the Transmission Service Provider shall Use assumptions consistent with the assumptions used in operations studies and planning studies for the applicable time periods, including: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R5.1. Use all Contingencies meeting the criteria described in its ATCID.

R5.2. Respect any contractual allocations of TTC.

R5.3. Modeling the impact of point-to-point reservations as follows:

Also, the term "interface point" is used several times both in MOD-28 and MOD-30. Please consider a more appropriate term such as balancing area.

R6.1. For Daily TTCs, it has been common practice to use the Monthly TTC value up until a few days prior to when the Daily service commences. This is done because weather and outage information is not substantially more accurate 7 days out than it is 30 days out. Day specific calculations are then performed serveral times during the current week as weather and outage information becomes more clear. Please consider the following wording.

Proposed wording: R6.1. At least once in the calendar week prior to the specified period for TTCs used in hourly, and daily ATC calculations.

R7. The wording in R7 appears to describe transfers involving single balancing area. Also, the wording does not mention contingency analysis. Please consider the following wording.

Proposed wording: Determine the first contingency incremental Transfer Capability for each Posted Path by increasing generation and/or decreasing load within the source Balancing Authority area(s) and decreasing generation and/or increasing load within the sink Balancing Authority area(s) until either:

The wording in b) is confusing. This also might fit better as another bullet under a). Please consider rewording b) and adding it as a bullet under a).

The language in c) "sum the incremental Transfer Capability and all impacts of Firm Transmission Service that were included in the study model" requires some clarification. It would be helpful to carify that it may not be appropriate to represent TTC as a simple sum of FCITC and net base transfers. If base transfers are in the same direction as the TTC being calculated, (i.e. base imports modeled when calculating import TTC), a simple summation is appropriate (TTCimport= FCITC + base imports). However, if base transfers are in the opposite direction to the TTC being calculated (i.e. base exports when calculating import TTC), a simple summation is not appropriate (TTCimport= FCITC - base exports is not accurate). The reason is that the counterflow effect of the base transfer usually does not correspond to a 1:1 increase in FCITC, and hence, summing a "negative" base transfer may significantly understate or overstate the TTC. The drafting team appears to have decided to address counterflow impacts in the calculation of ATC in R11 and R12. This approach will work if coordinated with the treatment of base flows in R7c&d. Please consider adding language such as the following.

Proposed wording: "Base transfers in the same direction as a TTC path shall be summed with the Incremental Transfer Capability to determine TTC. Base transfers in the opposite direction of a TTC path (i.e. net base exports when calculating import TTC and net base imports when calculating export TTC), which create counterflow effects that cannot generally be reconciled by a simple summation, shall be addressed in the calculation of TTC/ATC as described in the Transmission Operator's ATCID document."

R9. Need to add Conditional Firm Service to the ETCF equation. GFF needs to have the phase "reserved on posted Paths" added similar to NITSF.

R10. GFNF needs to have the phrase "reserved on posted Paths" added similar to NITSNF.

R11. To the extent base transfers provide counterflow impacts, these are already embedded in the TTC values. Is the "CounterflowsF" component of the equation intended to adjust the impact of counterflows resulting from the base transfers, or is it intended to account for counterflow impacts related to new transmission service commitments made prior to new models and transfer capabilities being developed? Please add clarification.

R12. Same comments as R11. Also, please consider using the term TRMNf instead of TRMu.

CBM should not be in the ATCNf equation as this will result in double counting. CBM is a reservation of TTC which prevents it from being sold on a firm basis. This capacity is sold on a non-firm basis. When an LSE needs to utilize the capacity it reserved as CBM to address a capacity shortfall, the LSE submits a transmission service request providing the specific source and sink information and referencing the need to access CBM capacity. To the extent the CBM capacity had been sold non-firm, those non-firm schedules would be curtailed to enable the LSE's to schedule its firm usage of CBM. This TSR or the subsequent schedule would be reflected in the ETCf value.

double count example) ATCnf = TTC - ETCf (includes 100 sched) -CBMs (100). Please consider this definition change.

Proposed wording: ETCf is the sum of existing firm Transmission commitments for the Posted Path during that period, which will include any transactions scheduled utilizing CBM capacity,

Please consider this definition for postbacks.

Proposed wording: PostbacksNF are increases to ATC values resulting from transmission service being redirected by customers to other paths or from transmission service not being scheduled by customers during that period, as defined in Business Practices

MOD-30 Comments

R2.1.1. This does not appear to be a criteria.

R2.1.2. This language is confusing regarding first three limiting elements. Also, planning and operating contingencies may include all elements, circumventing the concept of using representative flowgates. Please add clarification of what is intended.

R2.1.3 Any limiting element interconnection wide-seems overly broad. Should this be limited to those in which the TSPs area had some minimum impact?

R2.3. Since SOL is associated with contingency loading, the TFC is associated with the termal ratings of the facility, not necessarily the SOL of the flowgate. Please see suggested TFC definition.

R3 This section describes modeling requirements. It does not include provisions for outages, load forecasts, etc. R5 discusses outages when calculating AFCs. Is this intended to be done by inclusion in the modeling? If so, should this be moved into R3? Similarly, R6 discusses peak load forecasts when determining the impact to ETC. Is this intended to be included in the modeling. If so, should this be moved into R3?

R9. See comments related to CBM in R12 of Mod 28.

R10. This language is confusing. Also, although "P" is defined, it is not used in the equation. Please consider adding some simple language such as the following.

Proposed wording: "TTC is determined by dividing the most limiting flowgate capacity associated with a posted path by the path's distribution factor for that flowgate."

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | The Southeast Coalition |
| **Lead Contact:** | Roberto Paliza |
| **Contact Organization:** | Paliza Consulting, LLC. |
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| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Tina Lee | KGEN Hinds LLC & KGEN Hot Spring LLC | SERC | 5 |
| David Baugh<br>Woody Saylor | Cottonwood Energy LLC | SERC | 5 |
| Larry Rodriguez | Entegra Power Services | SERC & WECC | 5 & 6 |
| Rebecca Turner | Entegra Power Services | SERC & WECC | 5 & 6 |
| Terri Clynes | ConocoPhillips | **ERCOT,FRCC,MRO,RFC,**SERC,SPP & WECC | 5 & 6 |
| Ralph Honeycutt | Suez Energy Marketing | **ERCOT,RFC,NPCC,**SERC & WECC | 5 & 6 |
| Andy Sharer | LaGen/NRG Energy | SERC | 3, 4, 5 & 6 |
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*If more than one region or segment applies, please indicate all that do apply.  Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:
We strongly support the one year time-frame for complete implementation of the Standard and believe that some requirements of the Standard could be implemented earlier. TSPs should be encouraged and provided with flexibility to phase-in changes to their ATC calculations to meet the new requirements with the objective to complete all changes in one year.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

The term "Postback" is not standard in the industry and has not been defined in the Standard. A definition for this term should be included in the Standard.

Requirements R6.2, R6.3, and R6.4 of MOD-030 refer to transmission service "expected to be scheduled". Is this term being used to refer to reservations that are frequently scheduled as opposed to those that are infrequently scheduled? Please clarify.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement: Please see list below.

Counterflow:
MOD-001 (R4, R5.1). Requirements R4 and R5.1 of MOD-001 set the impact of counterflow to 0% in the calculation of firm ATC/AFC based on reservations and/or schedules, and calculation of non-firm ATC/AFC based on reservations. These requirements are not only technically incorrect because they do not provide any justification for the 0% counterflow setting and do not require Transmission Service Providers (TSPs) to provide any analyses, work papers, statistical scheduling data, etc. to justify a 0% counterflow or any other setting in their ATC/AFC calculations, they are also inadequate because they do not meet Order 890 Cite 293. The Standard should ensure consistent modeling of counterflows and require TSPs to provide a justification, along with work papers and analyses, for the counterflow percentage used in their calculations of firm and non-firm ATC/AFC. Additionally, a measurement to ensure that TSPs comply with providing justification for their counterflow settings should be added to the Standard.

- Updating of ATC Models:
  MOD-030 (R3). Requirement 9.3 of MOD-001 states that, at a minimum, monthly ATC values should be updated once a week. However, requirement 3.3 of MOD-030 states that the monthly models used for calculating monthly ATCs should be updated at least once per month. Requirement 3.3 is inconsistent with requirement 9.3 because monthly models should be updated at the same frequency as the monthly ATC values are updated, i.e. once a week. Otherwise, monthly ATC values may be inaccurate. Consistent with Cite 301 of Order 890, the Standard must "require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, e.g., generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities". The Standard, as proposed, is silent in regards to updating models and ATC values when a serious event such as the unplanned outage/return of a major transmission line occurs or a serious modeling error in ATC calculations is uncovered. In these situations, TSPs should be required to update models and ATC values as soon as practical rather than waiting for the scheduled update.

- Adjacent Systems Representation:
  MOD-030 (R3.5, R3.6). Requirements 3.5 & 3.6 establish the scope of adjacent systems to be included in ATC calculations. These requirements do not specifically require that adjacent systems be represented in a realistic manner or updated at the same frequency as the TSP system. Including three contiguous buses of the adjacent systems, as R3.5 requires, will not ensure an accurate representation of adjacent systems in the AFC models. These requirements fail to satisfy Order 890 at Cite 311 "to produce accurate determinations of ATC…". Furthermore, the Standard does not have a measure to assess the validity of adjacent systems representation and limits itself to only check that adjacent systems are included in the model (MOD-030, M7).

  In order to produce accurate ATCs, it is not enough to merely check that adjacent systems are included in the model. Instead, it is critical to validate the performance of these models on an on-going basis and ensure that adjacent systems are being properly updated in TSP models with data such as: load, generation profile, net interchange, transactions, and outages, provided by adjacent system entities.

  Use of PTDF term:

  MOD-030 (R2.1.3.1) Requirement 2.1.3.1 refers to generators that have at least a 5% Power Transfer Distribution Factor (PTDF) impact on a flowgate. Rather than PTDF, the proper term in this circumstance is Transfer Distribution Factor (TDF) because the flowgate could be either a PTDF or OTDF flowgate. The TDF term covers both cases.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☒ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments: Please see list below.

Consistency Between ATC calculations and Operational & Long-Term Expansion Studies: MOD-001 (R8). Requirement 8 of MOD-001 does not fully include the goals and requirements established in FERC Order 890/Cite 292 & 237 which are very clear about requiring TSPs to use data and modeling assumptions for ATC calculations that are consistent with those used in operations planning and long-term system expansion studies. FERC clearly states its expectation in the following extract of Order 890/Cite 292: "We find that requiring consistency in the data and modeling assumptions used for ATC calculations will remedy the potential for undue discrimination by eliminating discretion and ensuring comparability in the manner in which a transmission provider operates and plans its system to serve native load and the manner in which it calculates ATC for service to third parties". Furthermore, FERC establishes the following requirement in Citation 237 of Order 890: "We direct public utilities, working through NERC, to address, through the reliability standards process, any differences in developing TTC/TFC for transmission provided under the pro forma OATT and for transfer capability for native load and reliability assessment studies"
It is known that some Transmission Providers use a number of procedures such as: switching operating guides, generation re-dispatch, dropping load, etc. to mitigate transmission limit violations when performing reliability assessments of their systems in the planning horizon. Based on the application of mitigation procedures, these TSPs conclude that their transmission systems are reliable and thus, no transmission upgrades/reinforcements are needed. However, these mitigation procedures are not made available to third parties requesting transmission service and, as a result of this, transmission service requests are refused or the requestor is assigned financial responsibility for upgrading constrained facilities which could be mitigated by the application of the TSP operating procedures. Furthermore, these mitigation procedures typically are not included in the ATC models, which leads to artificial overloads, negative ATC/AFC, and the unduly discriminatory denial of transmission service.
We believe that requirement 8 of MOD-001 should fully incorporate the FERC directive in Order 890/Cite 292 & 237 and explicitly require TSPs to incorporate ALL data, modeling assumptions, and mitigation procedures used in operations planning and long-term expansion studies in their ATC/AFC models and calculations. A measurement to ensure full compliance with this requirement should be added to the Standard.

Over-Generation:
Order 890 at Cite 245 clearly establishes the requirement by which reservations from a generator in excess of the generator's nameplate capacity should not be simultaneously included in the calculation of ETC. Furthermore, FERC directed NERC to develop requirements in MOD-001 that lay out clear instructions on how to model a generator, which has reservations in excess of its nameplate capacity for a given time frame, to prevent unrealistic utilization of transmission capacity associated with over-generation. MOD-001 does not include the requirements directed by FERC to ensure that over-generation does not occur in the calculation of ETC.

ATC/AFC Coordination:

Requirement 10 of MOD-001 identifies the data set to be made available by Transmission Service Providers for ATC/AFC coordination purposes. Requirement 10 also establishes that this data needs to be made available by a TSP if there is a request by another TSP, Planning Coordinator, Reliability Coordinator, or Transmission Operator. Requirement 10 does not require the data set be exchanged by TSPs or the use of the data for coordination purposes. Thus, this requirement is inconsistent with Order 890 at Cite 310 whrein FERC directed TSPs to coordinate ATC/AFC and, as part of this directive, requires the establishment of a standard data exchange mechanism to enable the coordination process. Cite 310 of Order 890 states the following: "the Commission adopts the NOPR proposal and directs public utilities, working through NERC, to revise the related MOD reliability standards to require the exchange of data and coordination among transmission providers…". Furthermore, FERC in the last sentence of Cite 310 makes it clear that "As explained above, transmission providers are required to coordinate the calculation of TTC/TFC and ATC/AFC with others and this requires a standard means of exchanging data".
Therefore, it is clear to us that FERC's ultimate objective is the on-going coordination of TTC/TFC and ATC/AFC by transmission providers. To achieve this objective, requirement 10 of MOD-001 should be changed to mandate data exchange and on-going coordination of TTC/TFC and ATC/AFC among adjacent Transmission Service Providers.

Benchmarking of ATC Models:
Order 890 at Cite 290 & 291 requires NERC to modify ATC-related standards to incorporate requirements for the periodic review, update, and benchmark of models used for ATC calculations. FERC states the following in Cite 290: "this [requirement] means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers".
This cornerstone of Order 890, the accuracy of ATC calculations through review, updating, and benchmarking to actual events, has not been included in the ATC standard. Even if these requirements have been included in other reliability standards associated with ATC calculations, there should be a clear reference to these requirements in the ATC standard. Enforcing the above requirements - to review, update, and benchmark models used in ATC calculations - is essential to instill confidence in the market place and to obtain accurate and realistic ATC values.

Transparency:
Throughout Order 890, FERC has included various requirements to increase transparency in ATC calculations. In the spirit of Order 890 Cite 210 & 471 requirements, TSPs should be required to post all non-confidential input data & power flow models necessary to replicate their ATC calculations & results. If a data item used in ATC calculations is considered to be confidential, this data item should be identified as such and accordingly, documented in the TSP ATCID. Order 890 Cite 323 requires TSPs to document modeling assumptions, parameters, and methodologies used in their ATC calculations, and to make this documentation available along with work papers and analyses necessary to justify settings of ATC parameters.
We believe that requiring TSPs to post a comprehensive set of ATC input data, models, and documentation of their methodologies, is not only necessary to provide the transparency required by Order 890, but will enable market participants, transmission customers and regulators, to validate ATC calculations and use the models in their own analyses. This will increase confidence in ATC calculations, provide meaningful transparency, and significantly improve the overall ATC process.

Further, the general posting requirements to meet Order 890 transparency requirements should be included in MOD-001 and the posting details should be included in the business practices currently being developed by NAESB.
It is important to note that, currently, there are TSPs who post a great deal of ATC input data and power flow models. It is commendable that these TSPs have taken great strides in providing transparency. It is now time for other TSPs to follow suit.

Consistency of Modeling Practices:
Although MOD-001 states that its purpose is to promote "consistent application of ATC calculations" (as required by Order 890), this standard does not explicitly require consistent modeling practices to calculate ATC values for different time frames. It is known that some TSPs use different transmission models and modeling practices when calculating ATC values for different time frames. For example, the dispatch model used in the calculation of daily ATC values may be different than the dispatch model used in monthly ATC calculations. Another example is the representation of external systems in ATC models used for daily vs. monthly ATC calculations. These inconsistent modeling practices lead to inconsistent ATC values and reduced confidence in ATC calculations. TSPs should be required to eliminate or minimize inconsistent modeling practices. If inconsistent modeling practices can not be eliminated, TSPs should identify and document differences in models and modeling practices due to ATC calculation time frames and provide justification for them.

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: Please see below.

ATCID, TRMID, and CBMID Documentation:

Transmission Service Providers should make their ATCID, TRMID, and CBMID documentation publicly available as soon as these documents are ready but no later than 60 days before implementation. This is a very important issue for market participants who need to be aware of the TSP changes with enough lead time so that they can adjust their business processes accordingly. For those regions which have not had CBM in the past but TSPs decide to set aside transmission capacity for this purpose, according to the Standard, the CBMID should be posted 90 days before implementation to allow for consultation with NERC and a meaningful vetting of issues.

Stakeholders Participation:

Stakeholders' participation in the development and continued improvement of ATC standards and associated implementation is a key element to achieve success. NERC itself recognized the benefit and significance of the stakeholder process in the development of reliability standards. Order 693 at Cite 183. Thus, establishing forums and processes for stakeholders' on-going participation at NERC and regional levels is a MUST. These stakeholder processes are required to vet issues and gain support for the initial approval of the ATC standard and on-going changes to it. NERC should clearly set out and document the processes by which comments and suggestion of stakeholders will be gathered, evaluated, and incorporated in the Standard.

Distribution Factor Cut-Off:

MOD-030 (R10). Requirement 10 of MOD-030 establishes the mathematical equation to convert AFC values to ATC values and sets the distribution factor cut-off to 3% for ATC calculations. The following statement is included in requirement 10 of MOD-030: "a flowgate is impacted by a path if the Distribution Factor for that path is greater than 3%". Although most TSPs currently use a 3% distribution factor cut-off, there is no need to "hard-code" a value in the Standard and, by doing so, take away the flexibility of selecting a more appropriate value which could be set on a per flowgate basis. Furthermore, the TLR process uses a 5% distribution factor cut-off for transmission service curtailments which raises a potential conflict with the 3% cut-off value proposed for ATC calculation purposes.

NERC should address the difference between distribution factor cut-off values for ATC calculations and the TLR process to ensure that this difference does not create undue discrimination. Additionally, a minimum value of 3% for distribution factor cut-off could be included in the ATC standard provided TSPs are given flexibility to use a higher cut-off value which could be set on a per flowgate basis. Further, consistent with the transparency requirement of Order 890, TSPs should be required to provide justification for the distribution factor cut-off value(s) used in their ATC calculations.

ETC Calculation and Base Case Contingency Overloads:

MOD-030 (R6). Requirement 6 of MOD-030 attempts to define calculation of ETC based on flowgate impacts of various transmission service and load components. However, the ETC calculation as defined in requirement 6 is loose and unclear. More importantly, this requirement - as currently stated in the Standard – does not ensure that TSPs do not overstate flowgate capacity set aside for ETC purposes. FERC, in Order 890 Cite 243 & 244, has directed NERC to define ETC in a transparent and consistent manner to reduce the potential for undue discrimination. The following is an extract of Order 890 Cite 243: "To achieve greater consistency in ETC calculations and further reduce the potential for undue discrimination, the Commission adopts the NOPR proposal and directs public utilities, working through NERC and NAESB, to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses".

In some regions, overstatement of ETC leads to the appearance of "Base Case Contingency Overloads" (BCOs) which effectively means that the ETC impact on certain OTDF flowgates is greater than the flowgates capacity and thus, these flowgates are overloaded in the ATC power flow models. BCOs can be expressed by the following relationship:

BCO on a flowgate = ETC impact on the flowgate > Flowgate TFC

BCOs can occur in any of the ATC calculation time frames and may be spread over an entire region or be localized. In some TSP areas, BCOs have become a chronic situation and are mainly due to modeling flaws in the calculation of ETC. This causes serious problems for customers trying to get access to the transmission system. One of the main causes of chronic BCOs is the dispatch model which does not take into account transmission limitations and thus, yields unrealistic results.

Requirement 6 of MOD-030 does not address the dispatch model in enough detail to prevent unrealistic ETC results nor includes sanity checks to validate ETC calculations. Furthermore, TSPs are not required to show that the dispatch model in their ATC calculations is feasible and resembles actual system operation. Thus, it is our opinion that the ATC standard has not fully met the ETC calculation requirement established in Order 890 at Cite 243 & 244.

We believe that, in the calculation of ETC, all resources should be dispatched in a feasible and realistic manner such that transmission limitations are respected to the extent possible. The ATC standard should include clear & detailed guidelines for dispatching generating resources so that accurate and realistic models are used in ATC calculations which in turn should yield realistic ETC values.

As required in Order 890 Cite 290 & 291, TSPs must be required to benchmark ETC calculations against real-time flows to ensure that these values are not being overstated. This will go a long way in reducing the potential for undue discrimination. Furthermore, TSPs should be required to identify and report, on a periodic basis, all BCOs over 5% and chronic BCOs to NERC for further investigation and action.

Monthly ATC Values:

MOD-001 (R2.3). Requirement 2.3 of MOD-001 states that TSPs shall calculate monthly ATC values at least for the current month plus the next 12 months. This requirement should clarify that TSPs currently calculating and posting monthly ATC values for a longer time period should continue doing so. For example, some TSPs have been posting monthly ATC values for 18 months which is useful in providing information to the market and enabling new business. The requirement should be drafted to encourage such TSPs to continue their existing posting practices rather than falling back to the minimum requirement.

Outages and Monthly ATC Values:

The Standard does not address in enough detail the modeling of transmission and generation outages in the monthly models used for monthly ATC/AFC calculation. Currently, there are no consistent practices in the industry for including or excluding outages of short duration, i.e. a few hours or days, in the monthly ATC calculations. Consistent with the Order 890 goals of accuracy and transparency, NERC should set clear guidelines on the duration and type of outages to be included in the calculation of monthly ATCs so that this process is transparent and consistent across the various regions.

Dispatch Model and Must Run Units:

The Standard has little detail and, practically, no guidelines on the dispatch model used in ATC/AFC calculations, except for the following statement included throughout the Standard: "Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run as they are expected to run". This is a high level statement that needs to be developed into clear and measurable requirements to ensure consistency and fairness in ATC calculations. The dispatch model is the most important single factor in the determination of ATC values and, in particular, the modeling of Must Run Units, which is a critical issue. Consistent with the transparency requirement of Order 890, the generation dispatch model used in ATC calculations must be transparent and this issue must be addressed by the Standard.

To reduce both the potential for undue discrimination and the number of "phantom congestion" incidents, and to improve accuracy of ATC calculations, NERC must develop detailed requirements for the dispatch model used in ATC calculations and establish measurements to evaluate compliance with the requirements. These requirements should be focused on the development and use of dispatch models that are realistic and consistent with well-established operational practices. To ensure that the model resembles actual system operation, the dispatch model should be benchmarked against real-time dispatch and consistency checks should be performed across the various ATC time frames.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
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**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Background Information

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**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

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The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
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- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

- Incorrect Definition: SRP supports those definitions provided in MOD-4, MOD-08 and MOD-29. SRP does not elect to comment on defined terms offered in MOD-28 or MOD-30.
- MOD-001-01 The term Posted Path should not be defined in the standard. Defining Posted Path conflicts with the Background Information provided by the Standards Drafting Team and duplicates FERC regulations in 18CFR37.6. Specifically, the request for comments stated
- "…Major Changes include-removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB business practices."

  Therefore, because Postings are not being addressed and because Posted Path is defined in CFR37.6, the term Posted Path should not be defined in a NERC standard and should be referenced as a FERC term.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement: Please refer to answers to question Q6 for examples

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element: Please refer to answers to question Q6 for examples

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☒ Yes

☐ No

If "Yes," please explain why and provide supporting information.
Comments: See Answer to question Q2

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments: SRP supports the WECC MIC MIS ATC Drafting Team and WestConnect responses to this questionnaire. The comments offered below represent additional comments that have not been addressed by the WECC or WestConnect comments but are noteworthy nevertheless.

MOD-001

MOD-001-1 R1."Each Transmission Operator shall select one ATC methodology…" should be changed to "Each Transmission Service Provider shall select one ATC methodology…" to allow the entity that calculates ATC (R2) to choose the methodology.

MOD-001-1 R2 FERC regulations in 18CFR37.6 require postings for the time periods in R2.1, R2.2 and R2.3 for only constrained paths and only for firm ATC.

(1) Please explain the rationale for applying this regulation to unconstrained paths and to non-firm ATC for which FERC has different rules in place.

(2) Also, please explain the rationale for calculating more frequently than data is required by FERC to be posted.

(3) Consider removing R2 from the standard and instead referring to FERC regulations.

MOD-001-1 R2. If R2 remains, "Each Transmission Service Provider shall calculate ATC values for the time periods listed below…" should read "Each Transmission Service Provider shall calculate Firm ATC values for each constrained Posted Path for the time periods listed below…"

MOD-001-1 R3.4 and R3.5 The term "transfer capability" is used in these two standards. As R3. describes the ATCID presumably the term used here means "Available Transfer Capability" and should be changed to this term for clarity.

MOD-001-1 R4. and R5. While MOD-001-1 R4. directs the Transmission Service Provider to set the value of counterflows to zero for the calculation of firm ATC unless otherwise specified within the Transmission Service Provider's ATCID, no such similar standard exists to direct the Transmission Service Provider to set counterschedules to zero for the calculation of firm ATC under MOD-029-1.

This presumed oversight points out the risk involved when having one standard require use of a variable while another standard sets the value of that variable.

Another reason MOD-001 R4. and R5. should be moved from MOD-001-1 is that they do not fit into the Standard Drafting Team's explanation of the standard which is the following:

"MOD-001 – Available Transfer Capability. An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data."

SRP, therefore, recommends that:

(1) MOD-001-1 R4. and R5. be moved into each of MOD-028, MOD-029, and MOD-030. (2) SRP also recommends that when R4 and R5 are moved into MOD-029 they be modified to use the same term used in MOD-029 R7 and R8. That is, MOD-029 R7 and R8 currently use the term Counter-Schedules and MOD-001-1 R4 and R5 currently use the term counterflows. These terms should be the same.

MOD-001-1 R6. Perhaps instead of requiring e-mails it would be more efficient for the NERC Standards Drafting Team to request that NAESB develop a standard to require the ATCID, TRMID, and CBMID be posted on OASIS.  Then R6 could be removed as a standard.

MOD-001-1 R9. (1) Please explain how "update ATC" is different from "Post ATC" and (2) If it is the same thing, please remove the standard and work with NAESB to develop such a standard.

MOD-001-1 R9. (1) Please explain the rationale for requiring the Transmission Service Provider to "update" ATC at minimum frequencies as this standard does not support the goals of consistency or transparency. Each unnecessary calculation is a chance for the calculation, no matter how automated it is, to miscalculate and lead to lack of consistency.  (2) If R.9 is not removed, it should be reworded from "…shall update ATC at a minimum on the following frequency" to "shall review and update if necessary ATC at a minimum on the following frequency". The way this would be measured is there would be a violation if a variable changed and the ATC calculation was not updated within a certain time frame.

MOD-001-1 R10. As currently worded the data items listed must be provided by any of the entities listed and anyone can ask for the data.  R10 should be reworded from "Within 14 calendar days of a request of any Transmission Service Provider, Planning Coordinator…" to "Within fourteen calendar days of a request by any Transmission Service Provider, Planning Coordinator…"

Violation Severity Level for R9.  (1) The level of complexity suggested in this violation severity level will be very difficult to track and police.  It is impractical and should be greatly simplified to make it manageable.  (2) The use of the phrase "not calculated" also makes the description difficult to understand if not incorrect.  For example, the description in the Lower VSL column reads "For Hourly, not calculated within 5hrs … etc"

Reading that literally if I calculate Hourly 5 or more hours after the hour in question I have satisfied the criteria for the Lower VSL. This was obviously not the intent. A more appropriate wording for this description would be "For Hourly, calculated from 1 to 5 hours after the fact … etc" It is recommended that the description for all the levels of compliance for this requirement be changed replacing the phrase "not calculated" with "calculated" and changing the rest of the descriptions appropriately.

MOD-029

MOD-029-1 R1.12 The wording of this requirement does not match the form of those that precede it (i.e. R1.1 thru R1.11). It is a sub-requirement of the overall requirement R1. which stipulates that the TOP use a model to calculate TTC that "meets the following criteria:" The other sub-requirements stipulate that the model "includes" or "uses" or "models" certain items. R1.12 as written stipulates that the model "identifies" the percent fault damping used. This requirement would be more appropriately located in the requirement which stipulates what the study report must identify (R2.8) rather than what the model must identify.

MOD-029-1 Violation Severity Level for R1. This is a two part requirement for each of the four levels of severity. The first part is reasonable but the second part is not practical. To verify that the facility ratings used by the TOP in the model he used to calculate TTC are the same as those specified by the TO, the compliance person would have to manually compare the rating supplied with the rating used for hundreds even thousands of facilities in the model. Moreover, this would have to be done for every model used for every TTC established for every Posted Path. There may be many models representing several different years in the future. Even if you could overcome that hurdle and you found a few facility ratings that were wrong in a model, how would you verify that "…one of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths?" An erroneous facility rating is only important if it should have been the limiting factor but wasn't. You could only determine that if you corrected the erroneous facility rating in the model and rerun the study. Thus this test for compliance is very impractical and should be modified.

In the WECC, facility rating coordination is done by sharing the model with the effected entities before running the study. Once the affected entities have reviewed the model and are satisfied that it models their system appropriately they give their ok to run the study. (1) The requirement should be changed to say that the TSP shared the model with affected entities for their review of facility ratings. (2) The measure would be that the TSP can demonstrate that each of the affected entities reviewed the model and are satisfied with it. (3) The vsl would be that the TSP was able to demonstrate that all but one or two etc of the affected entities reviewed the model and were satisfied with it.

MOD-029-1 R7 Please explain the reliability reason for requiring Counter-SchedulesF in the formula for ATCF.

Paragraph 212 of Order 890 reads in part, "(1) for firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows."

MOD-004

MOD-004-1 Violation Severity Level for R3  The Moderate and High VSL columns each have two subparts.  The wording for the first subpart for each is identical.  Thus if I don't comply with the first subpart it is unclear whether the level of non-compliance is Moderate or High.  Also, the second subpart for the Moderate and High VSL columns are very similar in wording and are overlapping.  If the GCID changed by more than 20MW but not more than 30MW the noncompliance falls into both the Moderate and the High VSL.

MOD-004-1 Violation Severity Level for R7  The phrase "did not provide" should be changed to "provided" in all four levels of severity because the way it is currently written an entity could provide the requested data within the required seven days and still be non-compliant.

MOD-008

MOD-008-1 Throughout MOD-008-01 including in the "Applicability" section the term "Transmission Operator" should be replaced with the term "Transmission Owner".  In cases where a line is jointly owned, the Transmission Operator will calculate TTC of the facility, but each individual Transmission Owner will calculate their own TRM. It is not correct to say the Transmission Operator of the line tells the other line owners what their TRM will be.

MOD-008-1 Future Development Plan: Anticipated Actions #7 (first page of the standard)  The phrase "Board Adopts MOD-001-1" should be changed to read "Board adoption" to be consistent with the other standards.

MOD-008-1 Violation Severity Level for R3  "Moderate Level" should be reworded as follows:The Transmission Operator provided its TRMID to all but one entity specified in R3.  OR  provided its TRMID to all entities in 14 calendar days or more but less than 30 calendar days.

MOD-008-1 Violation Severity Level for R3 "High VSL" should be reworded as follows:

The Transmission Operator provided it's TRMID to all but two entities specified in R3. OR provided its TRMID to all entities in 30 calendar days or more but less than 60 calendar days.

MOD-008-1 Violation Severity Level for R3 "Severe VSL" should be reworded as follows:

The Transmission Operator did not provide the TRMID to any of the entities specified in R3 OR provided its TRMID to all entities in 30 calendar days or more but less than 60 calendar days.

AFFIRMATIVE COMMENTS:

In addition to the affirmative comments provided in the WECC and the WestConnect comments SRP wishes to emphasize that it is very supportive of the drafting team's incorporation of the following attributes into the draft standards:

Twelve Month Implementation Plan – The draft standards impose new requirements for the calculation of ATC and it's components that will require substantial effort and time in order to implement. It is envisioned that at a minimum twelve months will be required to make the changes necessary to conform to the new standards.

MOD029 Modeled after WECC Path Rating Methodology – SRP congratulates the drafting team for giving full consideration of the WECC Path Rating Methodology when drafting the MOD029 Rated System Path Methodology Standard. The WECC methodology has been developed and refined over a number of years and has served the west well. We are happy that the key features have been retained in MOD029. The requirements in R2. and its sub-requirements are particularly important to us and we would be very disappointed if any of the features of these requirements are degraded as a result of the drafting teams response to industry comments.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

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- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

Tacoma Power supports the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition:

Tacoma Power supports the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

Tacoma Power supports the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

Tacoma Power supports the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

1) Tacoma Power supports the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.

2) In reference to MOD-030-1/R10, the requirement should be altered as follows: "The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC's for its network and provides a tool for AFC-to-ATC conversion (in BPA's case, Power Utilization Factor Calculators). At this time, this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Mark Graham | |
| Organization: | Tri-State Generation and Transmission Association | |
| Telephone: | 303-452-6111 | |
| E-mail: | mgraham@tristategt.org | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
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| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
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| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

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On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
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- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
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**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

   ☐ Yes

   ☐ No

   If "Yes," please identify your concerns. Comments:

2. If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

   Incorrect Definition:

3. If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

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   Incorrect Measure or Compliance Element:

5. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If "Yes," please explain why and provide supporting information.
   Comments:

6. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

   Comments: General comments:

   Calculation and posting of hourly ATC will require knowledge of actual, preschedule, and real-time loads and other information. Tri-State is concerned that such information is to be shared only with TOs and other reliability entities, and encourages the drafting team to retain this limited distribution feature. On another level, compilation of this data comprises another set of confidential information the TO/TSP must track. These are now limited to transmission entities, but all it would take to violate confidentiality is one stroke of the pen - or one knowledgeable hacker.

The standard does not require validation.  Tri-State finds that this may be a serious shortcoming of the proposed standards. Without some mechanism to verify actual flows from time to time, including loop-flow accommodation, the standards are nothing more than a documentation and data storage burden to utilities. It is difficult to imagine a simple validation method and process, but if there was one in place it might be possible to evaluate how accurate ATC values were after the fact.

Related to this, no load-forecast probability level is specified for calculation of TRM/CBM/ETC. While we use low-exceedance probability forecasts for long-range transmission studies, this is not appropriate for short term ATC calculations. On the hourly time-frame, this would be manifested as load forecast bias. In other words, the firm ATC calculation process would naturally include some load margin to ensure that resulting ATC values will meet a defined risk level. Risk-level is a matter of company policy, so ATC will not necessarily be consistent from one utility to another. However, there should be a requirement to state the forecast probability level.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | W. Shannon Black ON BEHALF OF WECC MIC MIS ATC & OTHERS LISTED | |
| Organization: | Sacramento Municipal Utility District | |
| Telephone: | 916-732-5734 | |
| E-mail: | sblack@smud.org | |

| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment** **(check all industry segments in which your company is registered)** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
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| ☐ **NA – Not Applicable** | ☒ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

| | |
|---|---|
| **Group Name:** | WECC MIC MIS ATC TF Drafting Team **** |
| **Lead Contact:** | W. Shannon Black **** |
| **Contact Organization:** | SMUD |
| **Contact Segment:** | See below. |
| **Contact Telephone:** | (916) 732-5734 |
| **Contact E-mail:** | sblack@smud.org |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Abbey Nulph - WECC MIC MIS ATC TF Drafting Team | BPA | **WECC** | 1-3-5-9 |
| Chuck Falls - WECC MIC MIS ATC TF Drafting Team | SRP | WECC | 1-3-5-9- |
| Dave Lunceford - WECC MIC MIS ATC TF Drafting Team | CAISO | **WECC** | 2 |
| Jerry Smith - WECC MIC MIS ATC TF Drafting Team | APS | WECC | 1-3-5-9 |
| W. Shannon Black- WECC MIC MIS ATC TF Drafting Team | SMUD | WECC | 1-3-5-9- |
| | | | |
| **** Comments drafted by the WECC MIC MIS ATC TF Drafting Team are not those solely of the drafting team but represent the technical support and expertise of multiple agencies and entities. Those names and entities appearing below provided technical support and review of these comments and stand "in support" of these comments in addition to any additional comments their firms may | ****These comments represent 37 individuals from varying technical bakgrounds representing 25 separate entities and approximately 35-45 million people. | | |

| | | | |
|---|---|---|---|
| make aside from these WECC comments. It is estimated that these entities will implement ATC for an estimated 35-45 million people. | | | |
| Ron Schellberg | Idaho Power Company | WECC | 1-3-5-9 |
| John Collins | Platte River Power Authority | WECC | 1-3-5-9 |
| Rich Salgo | SPPC | WECC | 1-3-5 |
| Rich Salgoz | Nevada Power Company (NEVP - the Nevada Companies) | WECC | 1-3-5 |
| Brian Jobson | SMUD | WECC | 1-3-5-9 |
| Patricia vanMidde, FERC Case Manager | SDG&E | WECC | 1-3-4-5- |
| Mariam Mirzadeh P.E. | Western Area Power Administration - SNR | WECC | 1-3-4-5-6-7-8-9- |
| Jason Murray, MBA | Alberta Electric System Operator (AESO) | WECC | 1-9 |
| John Dalessi, Director, (Navigant Consulting) | Transmission Adminstration of Northern California | WECC | 1 |
| Paul Arnold, Vice President | Columbia Grid | WECC | 1 |
| Marc E. Donaldson, P.E., MGR | NorthWestern Energy | WECC | 1-3 |
| Rob Potter, FERC Analyst | Portland General Electric | WECC | 1-3-5-6-7-8 |
| Bob Easton | WAPA: RMR, DSW and SNR regions | WECC | 1-3-4-5-6-7 |
| John Burnett / Sueyen McMahon | LADWP | WECC | 1-3-5-6-9 |
| Raquel Aguilar / Ron Belva<br>Carol Ballantine<br>Dick Buckingham<br>Mee Charles<br>Patrick Damiano<br>Maria Denton / Dennis Gerlach<br>Teresa Kuehneman<br>Linda Finley<br>Steve Knudsen<br>Dilip Mahendra / Phil O'Donnel<br>Robert Schwermann / Tad Simms<br>Steve Sorey, MRG<br>Casey Sprouse | Tuscon Power<br>Platte River Power Authority<br>SMUD<br>St. of Ca.<br>Consultant<br>SRP<br>SRP<br>Snohomish Public Power<br>BPA<br>SMUD<br>SMUD<br>SMUD<br>SMUD | WECC<br>WECC<br>WECC<br>WECC<br>WECC<br>WECC<br>WECC<br>WECC<br>WECC<br>WECC<br>WECC<br>WECC<br>WECC | 1-3<br>1-3-4-5-6-9<br>1-3-5-9<br>3-4-5-6-7-9<br>1-2-3-4-5-6<br>1-3-5-9<br>1-3-5-9<br>1-3-5-9<br>1-3-5-9<br>1-3-5-9<br>1-3-5-9<br>1-3-5-9<br>1-3-5-9 |

| | | | |
|---|---|---|---|
| Gary Tarplee | SMUD | WECC | 1-3-5-6 |
| Phil Tice | SMUD | WECC | 1-3-5-6 |
| Raymond Vojandi | Grant County Public Utility | WECC | 1-3-4-5-6-7 |
| Lou Ann Westerfield | SCE | WECC | 9 |
| | Deseret Power | WECC | 6 |
| | WAPA | WECC | 1-3-4-5-6-9 |
| | Regulator | WECC | 9 |

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- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
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**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
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### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
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**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

The WECC MIC MIS ATC Drafting Team (hereafter "Team") solicited comments WECC-wide on all matters associated with this ATC filing. The Team solicited "in person" comments from 50+ members as well as the approximately 40 members of the WECC MIC MIS ATC TF advisory panel that served to provide the Team with continuing telephone and email advisory support on the technical issues associated with these filings.

The Team and those listed above echoe the concerns of the NERC Standards Drafting Team and strongly supports the inclusion of a 12 month implementation period for these standards. Particularly for MOD-29, the standard as drafted will require that numerous paths not previously exposed to the high rigors of the MOD-29 TTC determination process will have to be examined. Those entities electing the Rated System Path Methodology will require this much needed period to assure proper review of the Posted Paths under their perview. Without this period, or in the alternative, should a shorter period be mandated, it is highly likely that entities electing the RSP methodology will be in non-compliance as of any implementation date short of the full 12 months recommended.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: The Team and those listed above support those definitions provided in MOD-01, MOD-4, MOD-08. The Team and those listed above do not elect to comment on defined terms offered in MOD-28.

The Team and those listed above note that Order 890, P. 212 requires that the NERC Drafting Team address "counterflows" but does not provide direction as to the meaning of that term. As the term is often used interchangeably to mean actual flows of energy, scheduling of energy or reservations of transmission for possible scheduling of energy, the Team and those listed above suggest that the NERC ATC Drafting Team clarify the meaning of the term as well as how it integrates into each proposed standard. Specifically, the NERC Team should clarify such items as: 1) is it a flow, a schedule or a reservation, 2) does it change characteristics based on the time frame examined (E.g. is it a reservation before it becomes a schedule?), 3) is it uni-directional or bi-directional. The term is used in numerous calculations but as presented is too vague to calculate rendering the formula opaque.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

- General Comments
-
- All standards should be checked for consistency in the use of the terms "calendar days" and "days." Of note, these terms may differ between the Requirements and the corresponding VSLs. E.g. MOD-4, R4 specifies "calendar days" whereas the VSL for this requirement stipulates "days."
-
- MOD-01
-
- R1. and R2.
- State "…for each Posted Path per time period…" and "…values for the time periods listed…" respectively. The term "time period" should be changed to "time horizon." This makes the language consistent with 890.
- R3.3.
- The Team and those listed above suggest breaking the "R" into two pieces for clarity. The existing wording of being "associated" with each Facility is overly vague.
-
- (New) R3.3 "The identity of the Planning Coordinator responsible for assessing the long term reliability of each Facility under the Transmission Provider's tariff." (This verbiage comes from the NERC Functional Model. As an alternative to the word "Facility", "Posted Path" should be considered.)
- (New) R3.X "The identity of the Transmission Operator responsible for the real time operating reliability of each Facility under the Transmission Provider's tariff." (This verbiage comes from the NERC Functional Model. As an alternative to the word "Facility", "Posted Path" should be considered.)
- R3.6
- The format of this sub-requirement does not match that of the other five sub-requirements ahead of it making the meaning unclear. The Team and those listed above suggest the following rewording:
-

- "R3.6. A description of the methodology(ies) used to allocate ATC among multiple lines or sub-paths within a larger Posted Path, including where applicable, any methodology(ies) used to allocate ATC among multiple owners of a single path."

- R4 and R5.

- These describe how counterflows are to be dealt with even though counterflows as a subcomponent of ETCs are addressed in MOD-28, R11 and R12; MOD-29, R7 and R8, and MOD-30, R8 and R9. The Team and those listed above suggest MOD-01, R4/R5 should be "cut" from MOD-01 and "pasted" into each of the MODs 28, 29 and 30 so that the reader / Applicable Entity can see the self-contained algorithm requirements in each of those three methodlogies rather than having to cross reference (hunt and peck) between 28/29/30 and MOD-01. Since counterflows are always the last element mentioned in 28/29/30, the Team and those listed above would suggest pasting the MOD-01 counterflow requirement into each standard as the last requirement in each.

- R10.

- The wording is difficult to follow and could be clearer as to which entity must provide what information. The Team and those listed above suggest the following rewrite without doing damage to the substance.

- Suggested redraft:

-

- "R10. Upon request from another Transmission Service Provider, Planning Coordinator or Reliability Coordinator, each Transmission Service Provider shall provide from the below specified list, only that data requested and only that data already in existence and in the possession of the Transmission Service Provider from which that specified data is requested. Provision of all data is subject to confidentiality and security requirements.

- R10.1 et al

- Keep the list of data as drafted except for R10.4. which is overly vague. Change R10.4 to read:

- (New) R10.4 "Network Integration Transmission Service capacity on an aggregated basis."

- ADD AN ADDITIONAL REQUIREMENT FOR CLARITY; BREAK THE EXISTING R10 INTO TWO PIECES:

- RXX. Each Transmission Service Provider providing information pursuant R10 shall do so:

- RXX.1 Within fourteen days of a request

- RXX.2 On the interval specified by the requesting entity, not to exceed more frequently than once per hour unless mutually agreed upon by the requestor and provider.

- RXX.3 In that format in which the data exists at the time of the request, unless otherwise agreed upon by the requestor and provider.
- Rxx.4 For the requested time period up to 13 months in the future.
-
- R10.13
- There is a stray right parenthesis after the word “Margin.”
- MOD-04
-
- R2
- The acronym “CBID” should be changed to “CBMID.”
- MOD-29
-
- R1.6.
- The Team and those listed above suggest this bullet be deleted. This is already addressed in R2 wherein the modeling process is dictated. In the RSP methodology, “peak load forecasts” are not used to stress the system; rather, load and generation are simulated to stress the system to its greatest capacity. There are cases when the highest forecasted load may not stress the system to its greatest utliization – which is the goal of Order 890 as addressed in R2 under the RSP.
-
- R2.3
- The Team and those listed above suggest correcting “…as determined by R1.2.1…” to read “…as determined by R2.1.”
-
- R5.
- The language describing Native Load should be changed from “reserved” to “allocated.” Allocated is the word most commonly used in conjunction with OASIS to describe this condition. The same change should apply to GF sub F.
- The language describing Grandfathered capacity includes the defined terms “Firm” and "Transmission Service." Use of these words as defined terms is inconsistent throughout the proposed standards. They should either be changed here to a lower case or all applicable areas in each proposed standard should be changed to the defined term.
- MOD-30

- 

- MOD-01 allows an entity to select multiple methodologies to determine ATC. For example, an entity may elect to use Flowgates inside their affected area whereas they may also elect to use the Rated System Path metholdogy at the interface of their affected area. Under this scenario, the applicable entity need not study Flowgates beyond the intersecting cut plane of its interface as the ATC at the interface falls not under MOD-30 but MOD-29. To prevent seams issues and unnecessary analysis the Team and those listed above highly recommend the following rewrite(s):

- 

- MOD-30, R2.1.2. All first Contingency transfer analyses from all adjacent Balancing Authority source/sink combinations either: a) to at least the first three limiting Elements / Contingency combiantions within the Transmission Operator's system or b) to the interface of the adjacent Balancing Authority where the Transmission Operator utilizes the Rated System Path methodolgy.

- 

- This concept also applies to: MOD-30, R3.5, R3.6, R5.1, R7.2 and R7.4.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

General:

The Team and those listed above are in support of chaging the Violation Risk Factors as specifically commented on by SERC.

Specific:

MOD-01

M9
There is an unnecessary word "the" following the word "show" in the second line of the measure.

VSL for R4.
The word "Firm" should be inserted before the word ATC as R4 only refers to Firm ATC.

VSL for R5.
The word "Non-Firm" should be inserted before the word ATC as R5 only refers to Non-Firm ATC.

MOD-04

M1
Suggested rewording: "Each Transmission Service Provider shall produce its CBMID evidencing inclusion of all specified information in R1."
This approach should also be taken at M1 for MOD-08.

M5
M5, line 3 states "…they it has based its CBM…" Please change to "…that it has based its CBM…"

VSL for R2
The acronym "CBID" should be changed to "CBMID."

VSL for R10
The VSL is unclear. The Team suggests it be rewritten to state, "The Transmission Service Provider failed to approve an Interchange Transaction Tag for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available."

D1.3 Data Retention
For clarity and consistency, the phrase "three calendar years" in the second through fifth bullets should be changed to "most recent three calendar years plus the current year."

MOD-08

M5
M5 is missing the right parenthesis after the word "data" on the first line.

VSL for R1
In the Moderate Level column, change the phrase "changes been" to "changes that have been".

MOD-29

M1.
M1 inaccurately calls for production of "models" used to derive TTC. As there are multiple conditions under MOD-29, R2 where a model does not dictate the predicate for TTC, M1 should be reworded to state "…shall produce the models, contracts, nomograms, reports or study results…"

Corresponding to:
1) Models in R2.1, R2.2. and R2.5;
2) Contracts in R.2.3 and R2.6;
3) Nomograms in R2.4;
4) Reports or studies in R2.7 and R2.8.

M1.3
The Team suggests correcting M1.3 from "…as stated in R1.1 through R.12…" to "…as stated in R1.1 through R1.12…"

M4.
If "M1" above is adopted, M4 is duplicative of M1 and should be deleted.

VSL for R4.
An SOL does not exist for every Posted Path. This VSL should be amended by changing the words "the SOL" in the High and Severe columns to read "any SOL". This makes the wording of the Requirement consistent with the wording of the Measure.

VSL R5, R6, R7, R8
These VSLs call for only a "severe" determination. They also mandate that the TSP "use" all the elements defined. However, the TSP will not "use" all the defined elements if they are not applicable. Thus, if a TSP does not "use" all elements defined because all the elements were not applicable – the TSP is in violation for not including null elements in its calcuation.

The Team and those listed above suggest these be rewritten to state: "The Transmission Service Provider did not use all affected elements as defined in…." This approach should help clarify that "zero" as an integer is an acceptable entry and that only those variables "affected" need be reported or acted upon.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

AFFIRMATIVE COMMENTS:

The NERC Team and those listed above are reminded that the WECC MIC MIS ATC TF Drafting Team has solicited its responses face-to-face from 50+ individuals on 11/28/07 in Portland (attendance sheet retained by WECC and can be made available on request) and has also been supported by the ongoing technical support from the 40+ members of the WECC MIC MIS ATC Advisory Panel (16 separate entities) over the last year of drafting. As such, the WECC Team comments have been widely vetted and represent a substantial base of technical knowledge and veracity and are not merely the comments of a single entity.

The WECC Team and those listed above make the following "positive" proactive comments that the below listed features and attributes are essental to the standards as proposed and should be retained in the event a counter-position may be suggested by any singular entity.

GENERAL

1) The Team and those listed above support retention of the three methods recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028).

2) The Team and those listed above strongly support the retention of the proposed one-year implementation period.

3) The Team and those listed above support allowing NAESB to address all "posting" issues as they directly affect OASIS.

MOD-001 UMBRELLA

1) The Team and those listed above support allowing the use of more than one methodology for calculation of ATC by any one entity. For example, the Team supports allowing any entity to use the Flowgate methodology inside their affected area while also using the Rated System Path methodology at its boundaries.

2) The Team and those listed above support allowing each entity to specify in its ATCID how it will treat counterflows / schedules. (R4., R5.)

3) The Team and those listed above support the aggregation of transmission capacity for grandfathered contracts when shared with neighboring requestors.

4) The Team and those listed above support the specifically limited universe of entities to which data sharing is required as prescribed in R10.

5) The Team and those listed above are in support of changing the Violation Risk Factors as specifically commented on by SERC.

MOD-029 RATED SYSTEM PATH TTC, ETC & ATC

1) The Team and those listed above strongly support retention of the requirement(s) in R2.2 that accommodate paths which are "flow limited" by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing practices without re-inventing the wheel where no such effort is required to meet FERC's goals of transparency and consistency.

2) The Team and those listed above strongly support retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.

3) The Team and those listed above strongly support retention of the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.

4) The Team and those listed above strongly support retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts, associated litigation and potential renegotiation of associated operational agreements while supporting FERC's mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation metholdogies is required.

5) The Team and those listed above strongly support the adoption of a definition for counterflow to clarify its application in each equation.

MOD-004 CBM

1) The Team and those listed above support the concept of allowing the LSE to decide how much CBM it needs to satisfy its resource adequacy requirements and the TSP determining how the total CBM requirement for all requesting LSE's is allocated among paths. This is the proper division of labor.

2) The Team and those listed above strongly support allowing the LSE scheduling rights to the CBM after declaration of an EEA2 or higher condition.

MOD-30

1) The Team and those listed above support the MOD-30, R3 and R6 requirements only as to those sub-bullets addressing the most reasonable approach to how often information should be updated.

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Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: ., | | |
| Organization: WestConnect | | |
| Telephone: 602-250-1135 | | |
| E-mail: Jerry.Smith@aps.com | | |
| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** WestConnect Transfer Capability Workgroup

**Lead Contact:** Jerry Smith

**Contact Organization:** Arizona Public Service Co.

**Contact Segment:**

**Contact Telephone:** 602-250-1135

**Contact E-mail:** jerry.smith@aps.com

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Jerry Smith | Arizona Public Service Co. | WECC | TO |
| Chuck Falls | Salt River Project | WECC | TO |
| W. Shannon Black | SMUD | WECC | TO |
| Phil Sanchez | Westen Area Power Administration - SNR | WECC | TO |
| Charlie Reinhold | WestConnect | WECC | TO |
| Sueyen McMahon | Las Angeles Department of Water and Power | WECC | TO |
| Leonard York | Westen Area Power Administration | WECC | TO |
| Jeni Mistry | Salt River Project | WECC | TO |
| John Hernandez | Salt River Project | WECC | TO |
| Jose Solva | Salt River Project | WECC | TO |
| Maria Denton | Salt River Project | WECC | TO |
| Brian Cole | Arizona Public Service | WECC | TO |
| Marilyn Franz | Sierra Pacific Power Corp./Nevada Power | WECC | TO |
| John Steward | Western Area Power Administration | WECC | TO |
| Terri Kuehneman | Salt River Project | WECC | TO |
| James Hsu | Salt River Project | WECC | TO |
| | | | |
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*If more than one region or segment applies, please indicate all that do apply.  Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

> **MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.
>
> **MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.
>
> **MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.
>
> **MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.
>
> **MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.
>
> **MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of 'ATC' Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability (ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin (CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin (TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
  - TTC
  - ETC (firm and non-firm)
  - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
  - TFC
  - AFC (firm and non-firm)
  - ETC (firm and non-firm)
  - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

The Team strongly supports the inclusion of a 12 month implementation period for these standards. Particularly for MOD-29, the standard as drafted will require that numerous paths not previously exposed to the high rigors of the MOD-29 TTC determination process will have to be examined.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: The Team agrees with the WECC's Comment that the NERC ATC Drafting team should clarify the meaning of the term counterflows.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

- General
- In General the WestConnect Teams agrees with the WECC Comments. In addition the WestConnect Team adds the following comments.
-
- All of the MODs should be reviewed for consistency in termonology. In particular the terms "day" and "calendar days".
-
- MOD-01
- R4. and R5. address how counter flows are dealt with in determining ATC. In MODs 28, 29 and 30 the use of counter flows are again addressed in the determining ATC. This leads to having to refer to two different documents when addressing counter flows. The WestConnect Team suggest using the WECC suggestion. WECC suggestion is "The Team suggests MOD-01, R5 should be "cut" from MOD-01 and "pasted" into each of the MODs 28, 29 and 30 so that the reader / applicable entity can see the self-contained algorithm requirements in each of those three methodlogies rather than having to cross reference

(hunt and peck) between 28/29/30 and MOD-01. Since counterflows are always the last element mentioned in 28/29/30, the team would suggest pasting the MOD-01 counterflow requirement into each standard as the last requirement in each."

- Requirement R10. should be rewriten to clarify that Transmission Service Provider is required to provide only the data requested and only the existing data that the Transmission Service Provider has possession of and in the format that this existing data is in.
- Change R10.4 so that the Transmission Service Provider provides Network Integration Transmission Service details on an aggregated basis.
- 
- MOD-04
- The Team suggest changing R2. to "within seven days of the effective day of a change."
- 
- MOD-08
- For a system where the Rated System Path method is used to determin ATC, the Transmission Operator for a path with multiple owners only operates the path. The Transmission Owner gets its contractual share of the TTC. In addition it is responsible for all the ATC calculation and determining the TRM associated with it contractual share of the path. In MOD-08 as currently written the Transmission Operator is responsible for requirements R1., R2., R4. and R5.. The Team recomends that requirements R1., R2., R4. and R5. be rewriten to make this the responsibility of the Transmission Owner for entities using Rated System Path.
- R.5 the Team suggest change "shall calculate" to "shall review and recalculate as necessary "
- 
- MOD-29
- R1.6. The bullet should be deleted. In the Rated System Path methodology "peak load forcast are not used to stress the system; rather, load and generation are simulated to stress the system. This is already addressed in R.2.
- 

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

The WestConnect Team is in support of lowering the VRFs as proposed in the SERC comments.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

In General the WestConnect Teams agrees with the WECC Comments. In addition the WestConnect Team adds the following comment.

Order 890 stresses transparency for ATC. The Team does not believe that Implementation Documents are tansparent to the transmission users in that there are no requirments for the documents to be made available to the users. The WestConnect Team suggest that all the Implementation Documents be made public on the TSP's OASIS.

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Please use this form to submit comments on the proposed set of ATC standards (MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030). Comments must be submitted by **December 14, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "ATC Standards" in the subject line. If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-947-3885.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| Telephone: | 970-461-7272 | |
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| **NERC Region (check all Regions in which your company operates)** | | **Registered Ballot Body Segment**<br>**(check all industry segments in which your company is registered)** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☒ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☒ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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*If more than one region or segment applies, please indicate all that do apply. Regional acronyms and segment numbers are shown on prior page.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). Project 2006-07 requires specific reliability practices be incorporated into these standards. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency and transparency in how CBM, TRM, TTC, AFC and ATC are calculated and allocated. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those modeling standards related to the determination of ATC.

The drafting team has created the following proposed standards:

**MOD-001 – Available Transfer Capability.** An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

**MOD-004 – Capacity Benefit Margin**. A standard that describes the requesting, calculation, and use of CBM.

**MOD-008 – Transmission Reliability Margin.** A standard that describes the calculation and use of TRM.

**MOD-028 – Area Interchange Methodology (previously called the Network Response ATC Methodology).** A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

**MOD-029 – Rated System Path Methodology**. A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

**MOD-030 – Flowgate Methodology (previously called the Network Response Flowgate Methodology).** A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

The diagram on the next page shows, at a very high level, the arrangement of requirements within the revised set of standards. The drafting team made many major changes to the standards based on feedback from stakeholders submitted in response to the last posting of these standards as well as feedback from NAESB and FERC. Major changes include:

- Defined several new terms – and changed the names of some of the methodologies. The most significant new term is, 'Posted Path' – this is used to define the boundaries for determining TTCs, TFCs, and ATCs.
- Changed the applicability so that the Transmission Operator determines TTC or TFC and the Transmission Service Provider determines ATC.
- Converted descriptive language into algorithms for calculating ETC and ATC.
- MOD-001 includes the basic requirement for the TSP to have an Available Transfer Capability Implementation Document (ATCID) – but if a particular method of calculating TTC or TFC requires that the TSP's ATCID have additional data or information, then the requirement for the TSP's ATCID to have that additional data or information is in the standard that includes the method for calculating TTC or TFC.

- Removed all requirements to make data or information 'publicly available' – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB Business Practices.
- Added measures and compliance elements.

## Arrangement of Requirements within the Proposed Set of ‘ATC’ Standards

### MOD-001, MOD-004, MOD-008 Apply to All Methodologies

**MOD-001**
**Available Transfer Capability**
**(ATC)**

- Identify ATC methodology used
- ATC Implementation Document
- Follow counterflow rules
- Calculate ATC at specified intervals
- Share ATC data and information

**MOD-004**
**Capacity Benefit Margin**
**(CBM)**

- CBM Implementation Document
- Request CBM
- Allocate CBM
- Update CBM
- Share CBM data and information
- Real-time use of CBM

**MOD-008**
**Transmission Reliability Margin**
**(TRM)**

- TRM Implementation Document
- Calculate TRM
- Share TRM data and information

### Choose One or More Methodologies

**MOD-028**
**Area Interchange Methodology**

- Method-specific ATCID elements
- Modeling requirements
- Basic Area Interchange calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-029**
**Rated System Path Methodology**

- Modeling requirements
- Basic Rated System Path calculations:
    - TTC
    - ETC (firm and non-firm)
    - ATC (firm and non-firm)
- Share TTCs

**MOD-030**
**Flowgate Methodology**

- Method-specific ATCID elements
- Identify Flowgates
- Modeling requirements
- Basic Flowgate calculations:
    - TFC
    - AFC (firm and non-firm)
    - ETC (firm and non-firm)
    - AFC to ATC
- Share TFCs

The implementation plan includes the proposed retirement of the following standards:

- **FAC-012 – Transfer Capability Methodology.** Now addressed in MOD-028, MOD-029, and MOD-030.

- **FAC-013 – Establish and Communicate Transfer Capabilities.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-002 – Review of TTC and ATC Calculations and Results.** Now addressed in MOD-028, MOD-029, and MOD-030. Also to be addressed in future NAESB Business Practices.

- **MOD-003 – Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values**. To be addressed in future NAESB Business Practices.

- **MOD-005 – Procedure for Verifying Capacity Benefit Margin Values**. Now addressed in MOD-004.

- **MOD-006 – Procedures for the Use of Capacity Benefit Margin Values**. Now addressed in MOD-004

- **MOD-007 – Documentation of the Use of Capacity Benefit Margin**. Now addressed n MOD-004

- **MOD-009 – Procedure for Verifying Transmission Reliability Margin Values**. Now addressed in MOD-008

The standard drafting team was charged with revising the ATC-related modeling standards to comply with the FERC directives and industry participant consensus recommendations and is coordinating its efforts with NAESB to ensure that there are no gaps and no overlaps in the combined requirements. Please review the revised standards and the implementation plan and then answer the questions on the following pages. Please submit comments by **December 14, 2007.**

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

**1.** The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?

☐ Yes

☒ No

If "Yes," please identify your concerns. Comments:

The WECC MIC MIS ATC Drafting Team (hereafter "Team") solicited comments WECC-wide on all matters associated with this ATC filing. The Team solicited "in person" comments from 50+ members as well as the 43 members of the WECC MIC MIS ATC TF advisory panel that served to provide the Team with continuing telephone and email advisory support on the technical issues associated with these filings. Western was part of the Team review, however, did not get consensus on it's comments in time to be included in the overall WECC response. Therefore, Western has submitted the WECC comments with our additional comments included as follows and in the appropriate location in this comment form:

General - Document is very wordy - beginning with the definition of "Proposed Effective Date" - need to cut down language throughout.

MOD-001 -
Posted Path definition clarification question.
M5 and D1.3 suggestions

MOD-004 -
point on R4.2.1

MOD-029 -
General comment regarding R2 conflicting with FAC-012
R6 - what is meant by "non-firm NITS"?
M1.2 and M1.3 are redundant; M8.1 and M9.1 are redundant
M7 - R.2.1 wrong reference.

General - under D1.3 - data retention - why not require ONE retention time frame?

The Team echoes the concerns of the NERC Standards Drafting Team and strongly supports the inclusion of a 12 month implementation period for these standards. Particularly for MOD-29, the standard as drafted will require that numerous paths not previously exposed to the high rigors of the MOD-29 TTC determination process will have to be examined. Those entities electing the Rated System Path Methodology will require this much needed period to assure proper review of the Posted Paths under their perview. Without this period, or in the alternative, should a shorter period be mandated, it is highly likely that entities electing the RSP methodology will be in non-compliance as of any implementation date short of the full 12 months recommended.

**2.** If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.

Incorrect Definition: The Team supports those definitions provided in MOD-01, MOD-4, MOD-08. The Team does not elect to comment on defined terms offered in MOD-28.

The Team notes that Order 890, P. 212 requires that the NERC Drafting Team address "counterflows" but does not provide direction as to the meaning of that term. As the term is often used interchangeably to mean actual flows of energy, scheduling of energy or reservations of transmission for possible scheduling of energy, the Team suggests that the NERC ATC Drafting Team clarify the meaning of the term as well as how it integrates into each proposed standard. Specifically, the NERC Team should clarify such items as: 1) is it a flow, a schedule or a reservation, 2) does it change characteristics based on the time frame examined (E.g. is it a reservation before it becomes a schedule?), 3) is it uni-directional or bi-directional. The term is used in numerous calcualtions but as presented is too vague to calculate rendering the formula opaque.

**3.** If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.

Incorrect Requirement:

- General Comments
-
- All standards should be checked for consistency in the use of the terms "calendar days" and "days." Of note, these terms may differ between the Requirements and the corresponding VSLs. E.g. MOD-4, R4 specifies "calendar days" whereas the VSL for this requirement stipulates "days."
- The documentation overall is very wordy - starting with the "Proposed Effective Date." - need to cut down language throughout.
- MOD-01
- Posted Path Definition - "Any BA to BA interconnections." Most TPs in the Western Interconnction do not post BA-BA interconnections as "paths". Is the intent here to be interpretted as "if you post BA-BA paths" vs. you shall post all interconenctions?
- R1. and R2.
- State "…for each Posted Path per time period…" and "…values for the time periods listed…" respectively. The terms "time period" should be changed to "time horizon." This locks the time window to a prescribed window and negates the ability to assign a random "time period."
-
- R3.3.

- The Team suggests breaking the "R" into two pieces for clarity. The existing wording of being "associated" with each Facility is overly vague.
- (New) R3.3 "The identity of the Planning Coordinator responsible for assessing the long term reliability of each Facility under the Transmission Provider's tariff." (As an alternative to the word "Facility", "Posted Path" should be considered.)
- (New) R3.X "The identity of the Transmission Operator responsible for the real time operating reliability of each Facility under the Transmission Provider's tariff." (As an alternative to the word "Facility", "Posted Path" should be considered.)
- R3.6
- The format of this sub-requirement does not match that of the other five sub-requirements ahead of it making the meaning unclear. The Team suggests the following rewording:
- "R3.6. A description of the methodology(ies) used to allocate ATC among multiple lines or sub-paths within a larger Posted Path, including where applicable, any methodology(ies) used to allocate ATC among multiple owners of a single path."
- R4 and R5.
- These describe how counterflows are to be dealt with even though counterflows as a subcomponent of ETCs are addressed in MOD-28, R11 and R12; MOD-29, R7 and R8, and MOD-30, R8 and R9. The Team suggests MOD-01, R5 should be "cut" from MOD-01 and "pasted" into each of the MODs 28, 29 and 30 so that the reader / applicable entity can see the self-contained algorithm requirements in each of those three methodlogies rather than having to cross reference (hunt and peck) between 28/29/30 and MOD-01. Since counterflows are always the last element mentioned in 28/29/30, the team would suggest pasting the MOD-01 counterflow requirement into each standard as the last requirement in each.
- R10.
- The wording is difficult to follow and could be clearer as to which entity must provide what information. The Team suggests the following rewrite without doing damage to the substance.
- Suggested redraft:
- "R10. Upon request from another Transmission Service Provider, Planning Coordinator or Reliability Coordinator, each Transmission Service Provider shall provide from the below specified list, only that data requested and only that data already in existence and in the possession of the Transmission Service Provider from which that specified data is requested. Provision of all data is subject to confidentiality and security requirements.
- R10.1 et al
- Keep the list of data as drafted except for R10.4. which is overly vague. Change R10.4 to read:

- (New) R10.4 "Network Integration Transmission Service capacity on an aggregated basis."
- ADD AN ADDITIONAL REQUIREMENT FOR CLARITY; BREAK THE EXISTING R10 INTO TWO PIECES:
- RXX. Each Transmission Service Provider providing information pursuant R10 shall do so:
- RXX.1 Within fourteen days of a request
- RXX.2 On the interval specified by the requesting entity, not to exceed more frequently than once per hour unless mutually agreed upon by the requestor and provider.
- RXX.3 In the format in which the data exists at the time of the request, unless otherwise agreed upon by the requestor and provider.
- Rxx.4 For the requested time period up to 13 months in the future.
- R10.13
- There is a stray right parenthesis after the word "Margin."
- D1.3 - data retention - why not make it all the same time period - say two years?
- MOD-04
- R2
- The acronym "CBID" should be changed to "CBMID."
- R4.2.1 - Western interconnection puts reserve sharing requirements in TRM, not CBM.
- MOD-29
- R1.6.
- The Team suggests this bullet be deleted. This is already addressed in R2 wherein the modeling process is dictated. In the RSP methodology, "peak load forecasts" are not used to stress the system; rather, load and generation are simulated to stress the system to its greatest capacity. There are cases when the highest forecasted load may not stress the system to its greatest utliization – which is the goal of the R2 under the RSP.
- General comment/question - does R.2 conflict with FAC-012?
- R2.3
- The team suggests correcting "…as determined by R1.2.1…" to read "…as determined by R2.1."
- R5.

- The language describing Native Load should be changed from "reserved" to "encumbered." Encumbered is the word most frequently used in conjunction with OASIS to describe this condition. The same change should apply to GF sub F.

- The language describing Grandfathered capacity includes the defined terms "Firm" and "Transmission Service." Use of these words as defined terms is inconsistent throughout the proposed standards. They should either be changed here to a lower case or all applicable areas in each proposed standard should be changed to the defined term.

- R6 - what is "non-firm capacity reserved for NITS"?

- D1.3 - why not require one retention time period - say two years?

- MOD-30

- MOD-01 allows an entity to select multiple methodologies to determine ATC. For example, an entity may elect to use Flowgates inside their affected area whereas they may also elect to use the Rated System Path metholdogy at the interface of their affected area. Under this scenario, the applicable entity need not study Flowgates beyond the intersecting cut plane of its interface as the ATC at the interface falls not under MOD-30 but MOD-29. To prevent seams issues and unnecessary analysis the Team suggests the following rewrite(s):

- MOD-30, R2.1.2. All first Contingency transfer analyses from all adjacent Balancing Authority source/sink combinations either: a) to at least the first three limiting Elements / Contingency combiantions within the Transmission Operator's system or b) to the interface of the adjacent Balancing Authority where the Transmission Operator utilizes the Rated System Path methodolgy.

- If adopted, this same concept would be applied to: MOD-30, R3.5, R3.6, R5.1, R7.2 and R7.4.

**4.** The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.

Incorrect Measure or Compliance Element:

General:

The Team is in support of lowering the VSLs as specifically commented on by SERC.

Specific:

MOD-01

M9
There is an unnecessary word "the" following the word "show" in the second line of the measure.

VSL for R4.
The word "Firm" should be inserted before the word ATC as R4 only refers to Firm ATC.

VSL for R5.
The word "Non-Firm" should be inserted before the word ATC as R5 only refers to Non-Firm ATC.

M5 - R5 is incorrect reference.

MOD-04

M1
Suggested rewording: "Each Transmission Service Provider shall produce its CBMID evidencing inclusion of all specified information in R1."
This approach should also be taken at M1 for MOD-08.

M5
M5, line 3 states "…they it has based its CBM…" Please change to "…that it has based its CBM…"

VSL for R2
The acronym "CBID" should be changed to "CBMID."

VSL for R10
The VSL is unclear. The Team suggests it be rewritten to state, "The Transmission Service Provider failed to approve an Interchange Transaction Tag for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available."

D1.3 Data Retention
Why not require one retention timeframe - say two years?

MOD-08

M5
M5 is missing the right parenthesis after the word "data" on the first line.

VSL for R1
In the Moderate Level column, change the phrase "changes been" to "changes that have been".

MOD-29

M1.
M1 inaccurately calls for production of "models" used to derive TTC. As there are multiple conditions under MOD-29, R2 where a model does not dictate the predicate for TTC, M1 should be reworded to state "…shall produce the models, contracts, nomograms, reports or study results…"

Corresponding to:
1) Models in R2.1, R2.2. and R2.5;
2) Contracts in R.2.3 and R2.6;
3) Nomograms in R2.4;
4) Reports or studies in R2.7 and R2.8.

M1.3

The Team suggests correcting M1.3 from "…as stated in R1.1 through R.12…" to "…as stated in R1.1 through R1.12…"

M4.
If "M1" above is adopted, M4 is duplicative of M1 and should be deleted.

M1.2 and M1.3 are redundant - remove one.
M7 - reference to R.1.2 seems incorrect.
M8.1 and M9.1 are redundant - remove one.

VSL for R4.
An SOL does not exist for every Posted Path. This VSL should be amended by changing the words "the SOL" in the High and Severe columns to read "any SOL". This makes the wording of the Requirement consistent with the wording of the Measure.

VSL R5, R6, R7, R8
These VSLs call for only a "severe" determination. They also mandate that the TSP "use" all the elements defined. However, the TSP will not "use" all the defined elements if they are not applicable. Thus, if a TSP does not "use" all elements defined because all the elements were not applicable – the TSP is in violation for not including null elements in its calcuation.

The Team suggests these be rewritten to state: "The Transmission Service Provider did not use all affected elements as defined in…." This approach should help clarify that "zero" as an integer is an acceptable entry and that only those variables "affected" need be reported or acted upon.

**5.** Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If "Yes," please explain why and provide supporting information.
Comments:

**6.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.

Comments:

AFFIRMATIVE COMMENTS:

The NERC Team is reminded that the WECC MIC MIS ATC TF Drafting Team has solicited its responses face-to-face from 50+ individuals on 11/28/07 in Portland (attendance sheet retained by WECC and can be made available on request) and has also been supported by the ongoing technical support from the 43 members of the WECC MIC MIS ATC Advisory Panel (16 separate entities) over the last year of drafting. As such, the WECC Team comments have been widely vetted and represent a substantial base of technical knowledge and veracity and are not merely the comments of a single entity.

The WECC Team makes the following "positive" proactive comments that the below listed features and attributes should be retained in the event a counter-position may be suggested by any singular entity.

GENERAL

1) The Team supports retention of the three methods recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028).

2) The Team strongly supports the retention of the proposed one-year implementation period.

3) The Team supports allowing NAESB to address all "posting" issues as they directly affect OASIS.

MOD-001 UMBRELLA

1) The Team supports allowing the use of more than one methodology for calculation of ATC by any one entity. For example, the Team supports allowing any entity to use the Flowgate methodology inside their affected area while also using the Rated System Path methodology at its boundaries.

2) The Team supports allowing each entity to specify in its ATCID how it will treat counterflows / schedules. (R4., R5.)

3) The Team supports the aggregation of transmission capacity for grandfathered contracts when shared with neighboring requestors.

4) The Team supports the specifically limited universe of entities to which data sharing is required as prescribed in R10.

5) The Team supports those comments submitted by SERC specifying suggested changes to the VSLs. However, this Team makes no comment on the VSLs as they affect MOD-28.

MOD-029 RATED SYSTEM PATH TTC, ETC & ATC

1) The Team strongly supports retention of the requirement(s) in R2.2 that accommodate paths which are "flow limited" by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing practices without re-inventing the wheel where no such effort is required to meet FERC's goals of transparency and consistency.

2) The Team strongly supports retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.

3) The Team strongly supports retention of the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.

4) The Team strongly supports retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts, associated litigation and potential renegotiation of associated operational agreements while supporting FERC's mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation metholdogies is required.

5) The Team strongly supports the adoption of a definition for counterflow to clarify its application in each equation."

MOD-004 CBM

1) The Team supports the concept of allowing the LSE to decide how much CBM it needs to satisfy its resource adequacy requirements and the TSP determining how the total

CBM requirement for all requesting LSE's is allocated among paths. This is the proper division of labor.

2) The Team strongly supports allowing the LSE scheduling rights to the CBM after declaration of an EEA2 or higher condition.

MOD-30

1) The Team supports the MOD-30, R3 and R6 requirements as representing the most reasonable approach to frequency of updating information.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

## Consideration of Comments on 3rd Draft of MOD-001; 2nd Draft of MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 — Project 2006-07

The ATC Standards Drafting Team thanks all commenters who submitted comments on the 3rd draft of MOD-001; 2nd draft of MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030. These standards were posted for a 45-day public comment period from October 31 through December 14, 2007. The standard drafting team asked stakeholders to provide feedback on the standards through a special SAR Comment Form. There were 51 sets of comments, including comments from more than 181 different people from more than 95 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving these standards forward to for 30-day pre-ballot review.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. (Note that not all commenters responded to all questions.) All comments received on these standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | A. L. Barredo (G3) | Florida Power & Light Company | | | ✓ | | | | | | | |
| 2. | Aaron Staley (G3) | Orlando Utilities Commission | | | ✓ | | | | | | | |
| 3. | Abbey Nulph (I) (G14) ** | Bonneville Power Administration | ✓ | | ✓ | | ✓ | ✓ | | | ✓ | |
| 4. | Al McMeekin (G11) | South Carolina Electric & Gas | ✓ | | ✓ | | ✓ | | | | | |
| 5. | Alan Adamson (G8) | New York State Reliability Council | | ✓ | | | | | | | | |
| 6. | Alessia Dawes | Hydro One Networks | ✓ | | ✓ | | | | | | | |
| 7. | Andy Sharer (G13) | LaGen/NRG Energy | | | ✓ | ✓ | ✓ | ✓ | | | | |
| 8. | Anita Lee (I) (G5) | Alberta Electric System Operator | | ✓ | | | | | | | | |
| 9. | Annie Tra (G3) | Seminole Electric Cooperative, Inc. | | | | ✓ | | | | | | |
| 10. | Art Brown (G10) | Santee Cooper | ✓ | | | | | | | | | |
| 11. | Art Nordlinger (G3) | Tampa Electric Company | ✓ | | | | | | | | | |
| 12. | Barry Green | EPSA | | | | | ✓ | ✓ | | | | |
| 13. | Bert Bressers | Southwest Power Pool | | ✓ | | | | | | | | |
| 14. | Biju Gopi (G8) | IESO | | ✓ | | | | | | | | |
| 15. | Bob Easton (G14) | WAPA: RMR, DSW and SNR regions | ✓ | | ✓ | ✓ | ✓ | ✓ | ✓ | | | |
| 16. | Brett Koelsch | Progress Energy, Carolinas | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 17. | Brian Cole (G15) | Arizona Public Service Co. | ✓ | | | | | | | | | |
| 18. | Brian Jobson (G14) | SMUD | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 19. | Bryan Hill (G11) | Southern Company | ✓ | | ✓ | | ✓ | | | | | |
| 20. | C. Robert Moseley (G9) | Public Service Commission of SC | | | | | | | | | ✓ | |
| 21. | Carol Ballantine (G14) | Platte River Power Authority | ✓ | | ✓ | ✓ | ✓ | ✓ | | | ✓ | |
| 22. | Carol Gerou (G7) | MP | | | | | | | | | | ✓ |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 23. | Casey Sprouse (G14) | SMUD | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 24. | Charles Yeung (G5) | SPP -- ISO/RTO Council (IRC) | | ✓ | | | | | | | | |
| 25. | Charlie Reinhold (G15) | WestConnect | ✓ | | | | | | | | | |
| 26. | Chris Advena | PJM Interconnection LLC | | ✓ | | | | | | | | |
| 27. | Chris Constantine (G2) | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 28. | Chuck Falls (I) (G14)** (G15) | Salt River Project | ✓ | | ✓ | | ✓ | ✓ | | | ✓ | |
| 29. | D. A. McInnis (G3) | Florida Power & Light Company | | | ✓ | | | | | | | |
| 30. | Dan Huffman (G2) | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 31. | Danielle Beaulieu (G4) | NPCC | ✓ | | | | | | | | | |
| 32. | Dave Folk (G2) | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 33. | Dave Huff (G2) | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 34. | Dave Lunceford (G14) ** | CAISO | | ✓ | | | | | | | | |
| 35. | Dave Rudolph (G7) | BEPC | | | | | | | | | | ✓ |
| 36. | David A. Wright (G9) | Public Service Commission of SC | | | | | | | | | ✓ | |
| 37. | David Baugh (G13) | Cottonwood Energy LLC | | | | | ✓ | | | | | |
| 38. | David Kiguel (G8) | Hydro One Networks | ✓ | | | | | | | | | |
| 39. | David Olivares | Modesto Irrigation District | | | | | | | | | | |
| 40. | Dee M. Reynolds | Fall River Rural Electric Cooperative | | | ✓ | ✓ | | | | | | |
| 41. | Dennis Gerlach (G14) | Salt River Project | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 42. | Dennis Kimm | MidAmerican Energy Electric Trading | ✓ | | ✓ | | | ✓ | ✓ | | | |
| 43. | Dick Buckingham (G14) | SMUD | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 44. | Dilip Mahendra (G14) | SMUD | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 45. | Dolores Stegeman | Tacoma Power | ✓ | | ✓ | ✓ | ✓ | ✓ | | | | |
| 46. | Don Reichenbach (G11) | Duke Energy - Carolinas | ✓ | | ✓ | | ✓ | | | | | |
| 47. | Donald E. Nelson (G8) | Massachusetts Dept. of Telecommunications and Energy | | | | | | | | | ✓ | |
| 48. | Donald Williams (G11) | PJM Interconnection LLC | ✓ | ✓ | ✓ | | ✓ | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 49. | Doug Bailey (G11) | TVA | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 50. | Doug Hohlbaugh (G2) | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 51. | Doug McLaughlin (G11) (G12) | Southern Co Transmission | ✓ | | ✓ | | ✓ | | | | | |
| 52. | DuShaune Carter (G11) (G12) | Southern Company Transmission | ✓ | | ✓ | | ✓ | | | | | |
| 53. | Earl Fair (G3) | Gainesville Regional Utilities | ✓ | | | | | | | | | |
| 54. | Elizabeth B. Fleming (G9) | Public Service Commission of SC | | | | | | | | | ✓ | |
| 55. | Eric Ruskamp (G7) | LES | | | | | | | | | | ✓ |
| 56. | Eugene Warnecke (I) (G11) | Ameren Services | ✓ | | ✓ | | ✓ | | | | | |
| 57. | G. O'Neal Hamilton (G9) | Public Service Commission of SC | | | | | | | | | ✓ | |
| 58. | Gary Tarplee (G14) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 59. | Greg Campoli (G8) | New York Independent System Operator, Inc (NYISO) | | ✓ | | | | | | | | |
| 60. | Greg Rowland | Duke Energy | ✓ | | ✓ | | | | | | | |
| 61. | Guy V. Zito (G8) | NPCC Regional Standards Committee | | | | | | | | | ✓ | ✓ |
| 62. | H. Steven Myers (I) (G5) | ERCOT | | ✓ | | | | | | | | |
| 63. | Helen Stines (G11) | APGI - Yadkin | ✓ | | | | ✓ | | | | | |
| 64. | J T Wood (G12) | Southern Company Transmission | ✓ | | | | | | | | | |
| 65. | Jack Cashin | EPSA | | | | | ✓ | ✓ | | | | |
| 66. | James Hsu (G15) | Salt River Project | ✓ | | | | | | | | | |
| 67. | Jason Murray, MBA (G14) | Alberta Electric System Operator (AESO) | ✓ | | | | | | | | ✓ | |
| 68. | Jason Shaver | American Transmission Company | ✓ | | | | | | | | | |
| 69. | Jay Campbell | Sierra Pacific Resources Transmission | ✓ | | | | | | | | | |
| 70. | Jeni Mistry (G15) | Salt River Project | ✓ | | | | | | | | | |
| 71. | Jerry Smith (I) (G14)** (G15) | Arizona Public Service Co. | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 72. | Jerry Tang (G11) | Municipal Electric Authority of GA | ✓ | | ✓ | | ✓ | | | | | |
| 73. | Jim Busbin (G12) | Southern Company Transmission | ✓ | | | | | | | | | |
| 74. | Jim Castle (G5) | New York Independent System Operator, Inc | | ✓ | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| | | (NYISO) | | | | | | | | | | |
| 75. | Jim Haigh (G7) | Western Area Power Administration | | | | | | | | | | ✓ |
| 76. | Jim Peterson (G10) | Santee Cooper | ✓ | | | | | | | | | |
| 77. | Jim Viikinsalo (G12) | Southern Company Transmission | ✓ | | | | | | | | | |
| 78. | Joachim Francis (G1) | Entergy Services Inc. | ✓ | | | | | | | | | |
| 79. | Joe Francois (G11) | Entergy | ✓ | | ✓ | | ✓ | | | | | |
| 80. | John Burnett (G14) | LADWP | ✓ | | ✓ | | ✓ | ✓ | | | ✓ | |
| 81. | John Collins (G14) | Platte River Power Authority | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 82. | John Dalessi, Director, (Navigant Consulting) (G14) | Transmission Administration of Northern California | ✓ | | | | | | | | | |
| 83. | John E. Howard (G9) | Public Service Commission of SC | | | | | | | | | ✓ | |
| 84. | John Hernandez (G15) | Salt River Project | ✓ | | | | | | | | | |
| 85. | John Steward (G15) | Western Area Power Administration | ✓ | | | | | | | | | |
| 86. | John Troha (G11) | SERC Reliability Corporation | | | | | | | | | | ✓ |
| 87. | Jon Loresch (G2) | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 88. | Jose Solva (G15) | Salt River Project | ✓ | | | | | | | | | |
| 89. | K. David Hagen | Clearwater Power Company | | | ✓ | | | | | | | |
| 90. | Kathleen M. Goodman (G8) | ISO-New England, Inc. | | ✓ | | | | | | | | |
| 91. | Ken Dizes | Salmon River Electric Cooperative | | | | | | | | | | |
| 92. | Ken Goldsmith (G7) | ALTW | | | | | | | | | | ✓ |
| 93. | Kenneth A. Sugden | Flathead Electric Cooperative | | | ✓ | | | | | | | |
| 94. | Kiet Nguyen (G11) | Associated Electric Cooperative, Inc | ✓ | | ✓ | | ✓ | | | | | |
| 95. | Kun Zhu (G6) (G7) | Midwest ISO | | ✓ | | | | | | | | ✓ |
| 96. | Larry Hartley (G2) | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 97. | Larry Middleton (G6) (G11) | Midwest ISO | ✓ | ✓ | ✓ | | ✓ | | | | | |
| 98. | Larry Rodriguez (G11) | Union Power Partners | | | | ✓ | ✓ | | | | | |
| 99. | Larry Rodriguez (G13) | Entegra Power Services | | | | | ✓ | ✓ | | | | |
| 100. | Laura Lee (G11) | Duke Energy - Carolinas | ✓ | | ✓ | | ✓ | | | | | |
| 101. | Leonard York (G15) | Western Area Power Administration | ✓ | | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 102. | Linda Finley (I) (G14) | Snohomish PUD | ✓ | | ✓ | ✓ | ✓ | | | | ✓ | |
| 103. | Lou Ann Westerfield (G14) | SCE | | | | | | | | | ✓ | |
| 104. | Marc Butts (G12) | Southern Company Transmission | ✓ | | | | | | | | | |
| 105. | Marc E. Donaldson, P.E., MGR (I) (G14) | NorthWestern Energy | ✓ | | ✓ | | | | | | | |
| 106. | Maria Denton (G14) (G15) | Salt River Project | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 107. | Maria Neufeld | Manitoba Hydro | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 108. | Mariam Mirzadeh P.E. (G14) | Western Area Power Administration - SNR | ✓ | | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | |
| 109. | Marilyn Franz (G15) | Sierra Pacific Power Corp./Nevada Power | ✓ | | | | | | | | | |
| 110. | Mark Graham | Tri-State Generation and Transmission Association | ✓ | | ✓ | | ✓ | | | | | |
| 111. | Matt Burns (G11) | Big Rivers Electric Cooperative | ✓ | | ✓ | | ✓ | | | | | |
| 112. | Matt Goldberg (G5) | ISO-NE | | ✓ | | | | | | | | |
| 113. | Mee Charles (G14) | St. of Ca. | | | ✓ | ✓ | ✓ | ✓ | ✓ | | ✓ | |
| 114. | Michael Brytowski (G7) | Midwest Reliability Organization (MRO) | | | | | | | | | | ✓ |
| 115. | Michael Toll (G11) | E.ON. U.S. | ✓ | | ✓ | | ✓ | | | | | |
| 116. | Mignon L. Clyburn (G9) | Public Service Commission of SC | | | | | | | | | ✓ | |
| 117. | Murale Gopinathan (G8) | Northeast Utilities | ✓ | | | | | | | | | |
| 118. | Narinder K Saini (G1) | Entergy Services Inc. | ✓ | | | | | | | | | |
| 119. | Neal Balu (G7) | WPS | | | | | | | | | | ✓ |
| 120. | Pam Oreschnick (G7) | XCEL | | | | | | | | | | ✓ |
| 121. | Patricia vanMidde, FERC Case Manager (G14) | SDG&E | ✓ | | ✓ | ✓ | ✓ | | | | | |
| 122. | Patrick Damiano (G14) | Consultant | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | | | | |
| 123. | Paul Arnold, Vice President (I) (G14) | Columbia Grid | ✓ | | | | | | | | | |
| 124. | Paul Graves (G3) | Progress Energy Florida | | | ✓ | | | | | | | |
| 125. | Phil Creech (G11) | Progress Energy - Carolinas | ✓ | | ✓ | | ✓ | | | | | |
| 126. | Phil O'Donnel (G14) | SMUD | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 127. | Phil Park | British Columbia Transmission Corporation | | ✓ | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 128. | Phil Riley (G9) | Public Service Commission of SC | | | | | | | | | ✓ | |
| 129. | Phil Sanchez (G15) | Western Area Power Administration - SNR | ✓ | | | | | | | | | |
| 130. | Phil Tice (G14) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 131. | Phuong Tran (G3) | Lakeland Electric | ✓ | | | | | | | | | |
| 132. | Ralph Honeycutt (G13) | Suez Energy Marketing | | | | | ✓ | ✓ | | | | |
| 133. | Ralph Rufrano (G8) | New York Power Authority | ✓ | | | | | | | | | |
| 134. | Randy MacDonald | New Brunswick System Operator | | ✓ | | | | | | | | |
| 135. | Randy Mitchell (G9) | Public Service Commission of SC | | | | | | | | | ✓ | |
| 136. | Raquel Aguilar (G14) | Tucson Power | ✓ | | ✓ | | | | | | | |
| 137. | Raymond Vojandi (G14) | Grant County Public Utility | ✓ | | ✓ | ✓ | ✓ | ✓ | ✓ | | | |
| 138. | Rebecca Turner (G13) | Entegra Power Services | | | | | ✓ | ✓ | | | | |
| 139. | Rene' Free (G10) | Santee Cooper | ✓ | | | | | | | | | |
| 140. | Rich Salgo (G14) | SPPC | ✓ | | ✓ | | ✓ | | | | | |
| 141. | Rich Salgoz (G14) | Nevada Power Company (NEVP -the Nevada Companies) | ✓ | | ✓ | | ✓ | | | | | |
| 142. | Rick Gonzales | New York Independent System Operator, Inc (NYISO) | | ✓ | | | | | | | | |
| 143. | Rob Martinko (G2) | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 144. | Rob Potter, FERC Analyst (G14) | Portland General Electric | ✓ | | ✓ | | ✓ | ✓ | ✓ | ✓ | | |
| 145. | Robert Coish (G7) | MHEB | | | | | | | | | | ✓ |
| 146. | Robert H. Easton | Western Area Power Administration - RMR | ✓ | | | | | | | | ✓ | |
| 147. | Robert Harshbarger | Puget Sound Energy | ✓ | | | | | | | | | |
| 148. | Robert Schwermann (G14) | SMUD | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 149. | Roberto Paliza (G13) | Paliza Consulting, LLC. | | | | | ✓ | | | | | |
| 150. | Rod Noteboom | Public Utility District #2 of Grant County, Washington | | | ✓ | ✓ | ✓ | | | | | |
| 151. | Roger Champagne (G4) (G8) | Hydro-Québec TransÉnergie (HQT) | ✓ | ✓ | | | | | | | | |
| 152. | Roman Carter (G12) | Southern Company Transmission | ✓ | | | | | | | | | |
| 153. | Roman Gillen | Consumers Power, Inc. | ✓ | | ✓ | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 154. | Ron Belva (G14) | Tuscon Power | ✓ | | ✓ | | | | | | | |
| 155. | Ron Carlsen (G12) | Southern Company Transmission | ✓ | | | | | | | | | |
| 156. | Ron Falsetti (I)(G5) (G8) | IESO | | ✓ | | | | | | | | |
| 157. | Ron Schellberg (G14) | Idaho Power Company | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 158. | Ron Slagel (G6) (G7) | MISO | | ✓ | | | | | | | | ✓ |
| 159. | Ross Kovacs (I) (G11) | Georgia Transmission Corporation | ✓ | | ✓ | | ✓ | | | | | |
| 160. | Sam Ciccone (G2) | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 161. | Scott Goodwin (G6) | Midwest ISO | | ✓ | | | | | | | | |
| 162. | Shayleah LaBray | PacifiCorp | ✓ | | | | ✓ | | | | | |
| 163. | Stan Shealy (G11) | South Carolina Electric & Gas | ✓ | | ✓ | | ✓ | | | | | |
| 164. | Steve Knudsen (G14) | Bonneville Power Administration | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 165. | Steve Sorey, MRG (G14) | SMUD | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 166. | Sueyen McMahon (G14) (G15) | LADWP | ✓ | | ✓ | | ✓ | ✓ | | | ✓ | |
| 167. | Tad Simms (G14) | SMUD | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 168. | Teresa Kuehneman (G14) (G15) | Salt River Project | ✓ | | ✓ | | ✓ | | | | ✓ | |
| 169. | Terri Clynes (G13) | ConocoPhillips | | | | | ✓ | ✓ | | | | |
| 170. | Terry Bilke (G7) | MISO | | | | | | | | | | ✓ |
| 171. | Terry Blackwell (G10) | Santee Cooper | ✓ | | | | | | | | | |
| 172. | Tina Lee (G13) | KGEN Hinds LLC & KGEN Hot Spring LLC | | | | | ✓ | | | | | |
| 173. | Tom Abrams (G10) | Santee Cooper | ✓ | | | | | | | | | |
| 174. | Tom Mielnik (G7) | Midwest Reliability Organization (MRO) | | | | | | | | | | ✓ |
| 175. | Vicente Ordax (G3) | FRCC | | | | | | | | | | ✓ |
| 176. | Vicky Budreau (G10) | Santee Cooper | ✓ | | | | | | | | | |
| 177. | W. R. Schoneck (G3) | Florida Power & Light Company | | | ✓ | | | | | | | |
| 178. | W. Shannon Black (G14) ** (G15) | Sacramento Municipal Utility District | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | | ✓ | ✓ | |
| 179. | Warren Clark | Avista Corporation | ✓ | | | | | | | | | |
| 180. | William Gaither (G10) | Santee Cooper | ✓ | | | | | | | | | |

| | Commenter | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 181. | William Phillips (G5) | MISO | | ✓ | | | | | | | | |
| 182. | Woody Saylor (G13) | Cottonwood Energy LLC | | | | | ✓ | | | | | |

(G1) — Entergy Services
(G2) — FirstEnergy
(G3) — FRCC
(G4) — Hydro-Québec TransÉnergie (HQT)
(G5) — ISO/RTO Council (IRC)
(G6) — Midwest ISO
(G7) — Midwest Reliability Organization (MRO)
(G8) — NPCC Regional Standards Committee
(G9) — Public Service Commission of South Carolina
(G10) — Santee Cooper
(G11) — SERC ATCWG
(G12) — Southern Company Transmission
(G13) — The Southeast Coalition
(G14) — WECC MIC MIS ATC TF Drafting Team **

**Comments drafted by the WECC MIC MIS ATC TF Drafting Team are not those solely of the drafting team but represent the technical support and expertise of multiple agencies and entities. Those names and entities appearing below provided technical support and review of these comments and stand "in support" of these comments in addition to any additional comments their firms may make aside from these WECC comments. It is estimated that these entities will implement ATC for an estimated 35-45 million people. These comments represent 37 individuals from varying technical backgrounds representing 25 separate entities and approximately 35-45 million people.

(G15) — WestConnect Transfer Capability Workgroup

## Index to Questions, Comments, and Responses

**1. The drafting team has proposed an Implementation Plan for these standards. Should additional time be provided for successful implementation?**

**Summary Consideration:** The majority of commenters supported the 12-month period, and no change has been made with regard to the duration. Some commenters requested that the effective dates in the standards be made consistent; the drafting team has done so, recognizing that the standards will now be posted for separate ballots. One commenter requested an 18-month period, and one commenter requested that the period be shortened; however, since the majority supported the 12-month period, these comments are being considered as outliers.

Two entities requested the implementation date and effective date language to be changed, such that the time required is not dependent on regulatory approvals; we reviewed the current language required by the Standards Committee, and believe the language used in the standard is correct. The drafting team cannot accurately predict a date when all applicable regulatory authorities will approve the set of standards. The proposed language allows the standards to move forward as quickly as the applicable regulatory approvals can be obtained.

The SDT corrected an error in the table that identifies the functional entities with responsibilities in the proposed standards. The first version of the implementation plan indicated that MOD-008 was applicable to six functional entities, and should have identified just the Transmission Operator and the Transmission Service Provider.
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| Commenter | Yes | No | 1. Comments on Implementation Plan |
|---|---|---|---|
| Alberta Electric System Operator | | | |
| Ameren Services | | ☑ | |
| American Transmission Company | | ☑ | |
| Arizona Public Service Co. | | ☑ | Arizona Public Service Co. strongly supports the inclusion of a 12 month implementation period for these standards. |
| Response: Thank you for your supportive comment. | | | |
| Avista Corporation | ☑ | | Avista strongly supports the inclusion of a 12-month implementation period for these standards.<br><br>A 12-month implementation period is particularly important for MOD-29. MOD-29, as drafted, will require that numerous paths not previously exposed to the high rigors of the MOD-29 TTC determination process will have to be examined. Avista anticipates that it will elect the Rated System Path Methodology for certain Posted Paths on Avista's system. Avista will, at a minimum, require a 12-month implementation period to assure proper review of the Posted Paths under the methodology. It will be difficult, if not impossible, to fully implement MOD-29 in the absence of the recommended 12-month implementation period. |

| Commenter | Yes | No | 1. Comments on Implementation Plan |
|---|---|---|---|
| Response: The implementation plan grants a 12-month period, and the SDT believes this supports your need, based on your comments. | | | |
| Bonneville Power Administration | | ☑ | This allotted time is sufficient and if shortened, would be a burden, especially for those entities electing to use the Rated System Path methodology that will require a much more rigorous TTC determination process than has historically been used. |
| Response: The Drafting team has not shortened the implementation period. | | | |
| British Columbia Transmission Corporation | ☑ | ☑ | We have two concerns, discussed in our comments below, that if not addressed may be problematic for a 12 month implementation, as BCTC may have difficulty in achieving compliance with any of the three ATC methodologies within 12 months. Our first concern is discussed in our comment 6.3 below regarding MOD-028-1, R7. MOD-028-1 will not be an option for BCTC if we cannot continue to use interpolation between representative TTCs (that we calculate according to the process described in R7). It will take BCTC longer than 12 months, if it is even practical, to develop the systems to calculate TTC with the same level of accuracy as we do today without interpolation, given the complexity of our system, the range of variable, limitations, and contingencies we consider to determine TTCs.<br>Response: The MOD-028 method requires an actual simulation of the system to calculate the TTC values. The drafting team does not believe an interpolation process conforms to the requirements of the standard. A deviation from this process could be obtained through a regional variance.<br>Our second concern is discussed in our comment 6.5 with respect to MOD-029-1 M-1. We believe that this requirement is redundant to M4. However, if it is retained as a specific requirement to produce models, BCTC will have a problem because it appears to retroactively require that models be produced for TTC calculations that were done in the past, and such models are no longer archived. BCTC does not use flow based methods, so MOD-030-1 is not applicable to us. For these reasons, for BCTC to be compliant within 12 months, it is important to us that the concerns described above and discussed further in our comments 6.3 and 6.5 be accommodated within the standards.<br>Response: The team agrees and has deleted the word model from M4. |
| Response: Please see in-line responses. | | | |
| Clearwater Power Company | | ☑ | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | | | |
| ColumbiaGrid, Inc. | | | [Intentionally left blank.] |
| Consumers Power, Inc. | | ☑ | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | | | |
| Duke Energy | ☑ | | Increased recalculation frequencies will require implementation of new methods and tools. Suggest effective date of 18 months after applicable regulatory approvals. |
| Response: The majority of the industry is supportive of this time period, and the drafting team believes this to be an appropriate duration, given the amount of work that will be required for many entities to become compliant. Entities should note that many of the requirements | | | |

| Commenter | Yes | No | 1. Comments on Implementation Plan |
|---|---|---|---|
| within these standards are based on Order 890, and efforts to become compliant with 890 can be started prior to the approval of these standards. Such efforts will likely aid in preparation for the compliance effort associated with these standards (e.g., researching software, performing studies, identifying divergent areas within current practice, etc…). | | | |
| Entergy Services Inc. | | ☑ | |
| EPSA | | ☑ | The implementation plan for the standard is too long. EPSA has not objected to NERC's recent request to FERC to extend by several months, the date when these standards will be submitted to FERC given the amount of work involved in developing these standards. However, to require up to 15 months beyond the date of regulatory approval for implementation of this standard is excessive. |
| Response: The majority of the industry is supportive of this time period, and the drafting team believes this to be an appropriate duration, given the amount of work that will be required for many entities to become compliant. Note that anyone can implement these standards earlier if they so choose. | | | |
| ERCOT | | | |
| Fall River Rural Electric Cooperative, Inc. | | ☑ | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | | | |
| FirstEnergy Corp. | ☑ | | 1. While we agree that the proposed Implementation Plan allows for sufficient time to achieve compliance with the various requirements, a successful implementation is reliant on tasks that must be completed in succession by NERC Responsible Entities who are not within the same organization. We encourage the standards drafting team to consider setting midpoint milestone dates, where appropriate, to allow sufficient time for entities that have tasks that are dependent upon the timely completion of other work prior to their own. Requirements for "implementation documentation" would be effective after 12 months, but then other data that relies on these documents should have additional time for implementation.<br><br>Response: Entities are expected to set their own mid-point milestone dates as appropriate within their own organizational structures, and, if necessary, establish contractual arrangements in support of meeting the requirements of the standards.<br><br>2. The Implementation Plan shows a table of the applicable entities for each proposed standard. In this table, the Purchasing-Selling Entity (PSE) is shown as applicable to MOD-008, but it is not listed as an applicable entity within the text of this standard or any of the proposed standards.<br><br>Response: The drafting team has modified the implementation plan to address this. |
| Response: Please see in-line responses. | | | |
| Flathead | | ☑ | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | | | |

| Commenter | Yes | No | 1. Comments on Implementation Plan |
|---|---|---|---|
| FRCC | | ☑ | |
| Georgia Transmission Corporation | | ☑ | GTC does not think that additional time is needed; however, GTC would like to point out that the implementation period should not be shortened. The standards require development of extensive NAESB business practice standards. NAESB's working plan requires approximately six months after NERC approval of the NERC standards to create NAESB business practices that implement the NERC standards. Therefore, entities that must implement the NERC standards will only have approximately six months after the NAESB standards to implement the combination of NERC and NAESB standards. |
| Response: The Drafting team has not shortened the implementation period. | | | |
| Hydro One Networks | | ☑ | |
| Hydro-Québec TransÉnergie (HQT) | | ☑ | |
| IESO | ☑ | | 1) The standards suggest retiring FAC-012 and FAC-013. We are uncomfortable with this since we strongly believe the MOD standards fall short of replacing these requirements and in our view the TTC should be determined within the FAC standards.<br><br>Response: The drafting team has analyzed the current FAC-012 and FAC-013, and believes that the requirements from those standards have been incorporated in the new MOD standards. In addition, TTC is not a physical facility rating, but rather an aggregate potential rating of multiple facilities based on contingency analysis. As such, we believe it to be a value determined through modeling and analysis that is based on facility ratings, and therefore place it in the MOD standards.<br><br>2) Tying the implementation date with the various regulatory approvals means that the effective dates will be all over the map. The effective dates should be set to a specific time after NERC BOT approval, that allows time for the appropriate regulatory approvals. These concerns were presented to NERC some time ago and it is our understanding that they had accepted this argument.<br><br>Response: The current language is that which has been specified for use by the NERC Standards Committee. |
| Response: Please see in-line responses. | | | |
| ISO/RTO Council (IRC) | ☑ | | Tying the implementation date with the various regulatory approvals for the MOD standards could mean effective dates can be varied across North America. A definitive effective date should be set that accounts for the time needed for appropriate regulatory approvals. |
| Response: The current language is that which has been specified for use by the NERC Standards Committee. | | | |
| Manitoba Hydro | | ☑ | |

| Commenter | Yes | No | 1. Comments on Implementation Plan |
|---|---|---|---|
| MidAmerican Energy Electric Trading | | ☑ | |
| Midwest ISO | | ☑ | |
| Modesto Irrigation District | | ☑ | MID supports the comments submitted by the Sacramento Municipal Utility District ("SMUD") on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | | | |
| MRO | | ☑ | |
| New Brunswick System Operator | | | |
| NorthWestern Energy (NWMT) | ☑ | | Not sure if this question is asking for additional time beyond the proposed implementation date or just a confirmation of what is proposed. I feel the proposed effective date language is sufficient. As mentioned below, the drafting team should review the effect date language in all six MODs to ensure consistency. |
| Response: The drafting team has reviewed the effective dates and made them consistent, recognizing that the standards will now be posted for separate ballots. | | | |
| NPCC Regional Standards Committee | | ☑ | |
| NYISO | | ☑ | Not applicable. |
| Response: No response required. | | | |
| PacifiCorp | | ☑ | PacifiCorp strongly supports the inclusion of a 12 month implementation period for these standards. The entities electing the Rated System Path Methodology will require this much needed period to assure proper review of the Posted Paths under their purview. |
| Response: Thank you for your supportive comment. | | | |
| PJM Interconnection LLC | | ☑ | This time allotted is sufficient but, if shortened, would be a burden. |
| Response: The Drafting team has not shortened the implementation period. | | | |
| Progress Energy, Carolinas | | | |
| Public Service Commission of SC | | ☑ | |
| Public Utility District #2 of Grant County, Washington | | ☑ | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | | | |
| Puget Sound Energy | ☑ | | The proposed effective date language is sufficient. As mentioned below, the drafting team should review the effect date language in all six MODs to ensure consistency. |
| Response: The drafting team has reviewed the effective dates and made them consistent, recognizing that the standards will now be | | | |

| Commenter | Yes | No | 1. Comments on Implementation Plan |
|---|---|---|---|
| posted for separate ballots. | | | |
| Salmon River Electric Cooperative | | ☑ | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | | | |
| Salt River Project | | ☑ | |
| Santee Cooper | | ☑ | |
| SERC ATCWG | | ☑ | This time allotted is sufficient but, if shortened, would be a burden. |
| Response: The Drafting team has not shortened the implementation period. | | | |
| Sierra Pacific Resources Transmission | | ☑ | NEVP and SPPC, the SPR companies, strongly support the inclusion of a 12 month implementation period for these standards. Particularly for MOD-29, the standard as drafted will require that numerous paths not previously exposed to the high rigors of the MOD-29 TTC determination process will have to be examined. Entities such as NEVP and SPPC electing the Rated System Path Methodology will require this period to assure proper review of the Posted Paths under their purview. Should a shorter period be mandated, it is highly likely that entities electing the Rated System Path Methodology will be in non-compliance as of any implementation date short of the full 12 months recommended. |
| Response: Thank you for your supportive comment. The Drafting team has not shortened the implementation period. | | | |
| Snohomish PUD | | ☑ | This allotted time is sufficient and if shortened, would be a burden, especially for those entities electing to use the Rated System Path methodology that will require a much more rigorous TTC determination process than has historically been used. |
| Response: The Drafting team has not shortened the implementation period. | | | |
| The Southeast Coalition | | ☑ | We strongly support the one year time-frame for complete implementation of the Standard and believe that some requirements of the Standard could be implemented earlier. TSPs should be encouraged and provided with flexibility to phase-in changes to their ATC calculations to meet the new requirements with the objective to complete all changes in one year. |
| Response: Thank you for your supportive comment. While the drafting team agrees with your suggestions regarding “phasing in” requirements, the drafting team is not mandating any specific schedule, other than the specific milestone at which entities must be compliant with all requirements in the standards. | | | |
| Southern Company Transmission | | ☑ | |
| SPP | | | No comment. |
| Tacoma Power | | ☑ | Tacoma Power supports the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | | | |
| Tri-State Generation and | | | |

| Commenter | Yes | No | 1. Comments on Implementation Plan |
|---|---|---|---|
| Transmission Association | | | |
| WECC MIC MIS ATC TF Drafting Team | | ☑ | The WECC MIC MIS ATC Drafting Team (hereafter "Team") solicited comments WECC-wide on all matters associated with this ATC filing. The Team solicited "in person" comments from 50+ members as well as the approximately 40 members of the WECC MIC MIS ATC TF advisory panel that served to provide the Team with continuing telephone and email advisory support on the technical issues associated with these filings.<br><br>The Team and those listed above echo the concerns of the NERC Standards Drafting Team and strongly supports the inclusion of a 12 month implementation period for these standards. Particularly for MOD-29, the standard as drafted will require that numerous paths not previously exposed to the high rigors of the MOD-29 TTC determination process will have to be examined. Those entities electing the Rated System Path Methodology will require this much needed period to assure proper review of the Posted Paths under their purview. Without this period, or in the alternative, should a shorter period be mandated, it is highly likely that entities electing the RSP methodology will be in non-compliance as of any implementation date short of the full 12 months recommended. |
| Response: Thank you for your supportive comment. The Drafting team has not shortened the implementation period. | | | |
| WestConnect Transfer Capability Workgroup | | ☑ | The Team strongly supports the inclusion of a 12 month implementation period for these standards. Particularly for MOD-29, the standard as drafted will require that numerous paths not previously exposed to the high rigors of the MOD-29 TTC determination process will have to be examined. |
| Response: Thank you for your supportive comment. | | | |
| Western Area Power Administration – RMR | | ☑ | The WECC MIC MIS ATC Drafting Team (hereafter "Team") solicited comments WECC-wide on all matters associated with this ATC filing. The Team solicited "in person" comments from 50+ members as well as the 43 members of the WECC MIC MIS ATC TF advisory panel that served to provide the Team with continuing telephone and email advisory support on the technical issues associated with these filings. Western was part of the Team review, however, did not get consensus on its comments in time to be included in the overall WECC response. Therefore, Western has submitted the WECC comments with our additional comments included as follows and in the appropriate location in this comment form:<br><br>General – Document is very wordy – beginning with the definition of "Proposed Effective Date" – need to cut down language throughout.<br>Response: We have made the language as clear and explicit as possible, which has in some cases resulted in some very "wordy" language.<br><br>MOD-001 –<br>Posted Path definition clarification question.<br>Response: It is unclear what is question is being asked.<br><br>M5 and D1.3 suggestions |

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>1. Comments on Implementation Plan</th></tr>
<tr><td></td><td></td><td></td><td>Response: It is unclear what is question is being asked.<br><br>MOD-004 –<br>point on R4.2.1<br>Response: It is unclear what point is being referred to.<br><br>MOD-029 –<br>General comment regarding R2 conflicting with FAC-012<br>Response: FAC-012 will be retired as part of the implementation plan associated with these standards.<br><br>R6 – what is meant by “non-firm NITS”?<br>Response: Non-firm NITS refers to network service from non-designated resources (NN-6).<br><br>M1.2 and M1.3 are redundant; M8.1 and M9.1 are redundant<br>Response: We have modified M1.2 and M1.3 to eliminate the redundancy; we do not believe M8.1 and M9.1 to be redundant, as one refers to ETC and the other refers to ATC.<br><br>M7 – R.2.1 wrong reference.<br>Response: We have modified R2.1 to point to the correct reference.<br><br>General – under D1.3 – data retention – why not require ONE retention time frame?<br>Response: These timeframes are based on NERC Compliance criteria, which varies based on the entities being discussed.<br><br>The Team echoes the concerns of the NERC Standards Drafting Team and strongly supports the inclusion of a 12 month implementation period for these standards. Particularly for MOD-29, the standard as drafted will require that numerous paths not previously exposed to the high rigors of the MOD-29 TTC determination process will have to be examined. Those entities electing the Rated System Path Methodology will require this much needed period to assure proper review of the Posted Paths under their purview. Without this period, or in the alternative, should a shorter period be mandated, it is highly likely that entities electing the RSP methodology will be in non-compliance as of any implementation date short of the full 12 months recommended.<br>Response: Thank you for your supportive comment.</td></tr>
<tr><td colspan="4">Response: Please see in-line responses.</td></tr>
</table>

**2. If there are any proposed definitions that you believe are incorrect, please identify the term and provide a substitute definition.**

**Summary Consideration:** The drafting team eliminated the use of the term "Posted Path" and replaced it with "ATC Path," which is now defined as "Any combination of Point of Receipt and Point of Delivery for which ATC is calculated."

The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks.

A definition for "Business Practices" was added, which reads: Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization business practices; or NAESB Business Practices.

The drafting team modified the approach to counterflow in the standards based on the comments provided. The default values were removed and a requirement for the ATCID to provide detail regarding how the TSP handles counterflows. Accordingly, the SDT believe this eliminated the need for a definition for Counterflows or the use of the separate term Counterschedules.

The SDT provided a new definition for Block Dispatch, which reads as follows: A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

The SDT provided a new definition for Dispatch Order, which reads as follows: A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

The SDT provided a new definition for Participation Factors, which reads as follows: A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

The drafting team removed references to "interface point" and "adjacent upstream TSP," instead now referring to "the immediately adjacent Balancing Authority associated with the Transmission Service Provider to (from) which the power is to be delivered (received)."

The drafting team has modified the definitions of Area Interchange Methodology and Rated System Path Methodology. The following sentence was added in MOD-028, "Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis." The following sentence was added in MOD-029, "Under the Rated System Path Methodology, and TTC results are generally reported as specific transmission path capabilities."

The SDT modified the definition of Flowgate Methodology to read as follows: The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on facility ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs are used to determine Available Transmission Capability (ATC).

The definition of AFC was expanded to include the relationship with CBM and TRM.

The SDT has modified the definition of Flowgate to read as follows: 1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System

The SDT has modified the definition of Power Transfer Distribution Factor to read as follows: In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer.

The SDT has modified the definition of Outage Transfer Distribution Factor to read as follows: In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).

The drafting team has also added a new definition for "Planned Resource Sharing Group (PRSG)" for those LSEs who have jointly agreed to meet their resource adequacy requirements.

The SDT modified the definition of Total Flowgate Capability to read as follows: The maximum flow capability on a Flowgate, not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), not to exceed the associated System Operating Limit.

The SDT made other minor corrections and clarifications as needed.

| Commenter | 2. Comments on Definitions |
|---|---|
| Alberta Electric System Operator | |
| Ameren Services | |
| American Transmission Company | |
| Arizona Public Service Co. | Arizona Public Service Co. agrees with the WECC's Comment that the NERC ATC Drafting team should clarify the meaning of the term counterflows.<br>Response: Please see responses to the WECC MIC MIS ATC Drafting Team.<br>In addition the NERC ATC Drafting team should clarify what is meant by the term post back.<br>Response: The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks. |
| Response: Please see in-line responses. | |
| Avista Corporation | In MOD-001, "Posted Path" is included as a defined term. "Posted path" is also defined in 18 CFR § 37.6 (b)(1)(i). Using a term that is already defined in the CFR may create confusion. Accordingly, Avista suggests that throughout the MOD standards, NERC replace the term "Posted Path" with a different defined term, such as "paths required to be posted", "paths requiring posting" or "paths for which ATC is calculated." |

| Commenter | 2. Comments on Definitions |
|---|---|
| Response: A new term, ATC Path, has been defined for use in the NERC standards to avoid conflicting with a term presently defined by FERC. It is defined as "Any combination of Point of Receipt and Point of Delivery for which ATC is calculated." | |
| Bonneville Power Administration | a. A definition for counterflow should be provided and used consistently in MOD-028, -029, and -030. A suggested definition follows: "Counterflow: the impact of schedules, reservations, or actual flows of energy in the direction opposite to the constraint."<br>Response: The drafting team has modified the approach to counterflow in the standards based on the comments provided. The default values were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 to include more detail regarding how the TSP handles counterflows. With this approach we do not believe that a definition of counterflow is required.<br>b. MOD-004 – In Order 890, FERC limited the use of CBM to meet generation reliability criteria – please clarify what is meant by "reserve adequacy requirements"<br>Response: When FERC refers to "generation reliability criteria" associated with CBM, the drafting tram believes they are referring to the need to have sufficient planning reserves to ensure generation to load balance (resource adequacy).<br>b. MOD-029 – The definition of Rated System Path Methodology incorrectly refers to ATC as "Available Transmission Capability" – this should be corrected to "Available Transfer Capability"<br>Response: We have changed the definition per your correction. |
| Response: Please see in-line responses. | |
| British Columbia Transmission Corporation | |
| Clearwater Power Company | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| ColumbiaGrid, Inc. | [Intentionally left blank.] |
| Consumers Power, Inc. | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Duke Energy | |
| Entergy Services Inc. | Definition of AFC in MOD-030-1 should be expanded to include CBM and TRM in addition to only committed uses similar to that for ATC in NERC standards.<br>Response: The definition has been modified to incorporate the suggestion. |

| Commenter | 2. Comments on Definitions |
|---|---|
| | MOD-028-1 R11 and R12 and MOD-030 R8 and R9 include a capitalized term Business Practices in Postback definition. The term Business Practices should either be defined, or clarified in the standard.<br><br>Response: The SDT has created a definition for "Business Practices." |
| Response: Please see in-line responses. | |
| EPSA | |
| ERCOT | |
| Fall River Rural Electric Cooperative, Inc. | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| FirstEnergy Corp. | MOD-004-1 – GCIR Definition: This definition may incorrectly imply that this is merely another resource that an LSE can use to meet its Resource Adequacy Requirements (RAR). RAR, such as planning reserve requirements (PRM), cannot be met with the use of CBM. Also, the definition refers to GCIR as "an alternative to internal resources" which may be misleading. The definition needs to address the fact that GCIR (as CBM) can only be used in an emergency. It is a "contingency option" rather than a "resource alternative". |
| Response: The STD has modified the definition to use the term you have suggested "resource adequacy requirements". The SDT disagrees that CBM cannot be used to meet RAR. It is up to the entity responsible for RAR to decide whether to allow the use of CBM (margin needed to import the GCIR). The very definition of CBM implies that this is so. The SDT also agrees that it can only be used in EEA 2 or higher and have added this concept to the definition. | |
| Flathead | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| FRCC | MOD-001-1: What is the "Time Horizon: Operations Planning"?<br><br>Response: "Time Horizon: Operations Planning" refers to a component of the NERC Compliance Monitoring and Enforcement Program, and is used in combination with the Violation Risk Factors and Violation Severity Levels to determine appropriate sanctions for a violation of a requirement of the standard.<br><br>R8 specifies "associated operations studies or planning studies for the time period studied". In order to be consistent with Order 890, it should specify "associated operating horizon studies or planning horizon studies for the product time period being calculated" and further, since these horizons are being used in the context of ATC determination, the prefix "ATC" should be added to eliminate ambiguity, just as the TPL standards do with near-term planning horizon (year 1 to year 5) and longer term planning horizon (years 6 to 10)<br><br>Response: The SDT believe the language is clear as written.<br><br>MOD-028-1: R5.3 – define "interface point" and "adjacent upstream TSP". This requirement is complex and it |

| Commenter | 2. Comments on Definitions |
|---|---|
| | should include examples with pictures.<br>Response: The drafting team has clarified the language as follows to eliminate the ambiguity. Rather than referring to "interface point" and "adjacent upstream TSP," we are now referring to "the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received." Similar language has been used to address the other related scenarios. |
| Response: Please see in-line responses. | |
| Georgia Transmission Corporation | MOD-028, -029 and -030 refer to "Postbacks" with a definition that uses the term "postback". There is not a definition in the NERC Glossary for this term. The current NAESB draft definition (dated 9/12/07) is "The increase in ATC due to a change in status of a Transmission Service request or the release of unscheduled Transmission Service." The following definitions are suggested for MOD-028, -029 and -030:<br>"Postbacks(F) are the changes in Firm ATC due to a change in Firm Transmission Service during that period, as defined in Business Practices";<br>"Postbacks(NF) are the changes in non-firm ATC due to a change in non-firm Transmission Service, as defined in Business Practices". |
| Response: The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks.. The drafting team has modified the formula definitions as follows:<br>"Postbacks(F) are the changes in Firm ATC due to a change in the use of Firm Transmission Service for that period, as defined in business practices";<br>"Postbacks(NF) are the changes in non-firm ATC due to a change in the use of non-firm Transmission Service for that period, as defined in business practices". | |
| Hydro One Networks | |
| Hydro-Québec TransÉnergie (HQT) | |
| IESO | MOD-004<br>CBM is intended to be used for accessing generation from external sources to meet the LSE's PLANNED capacity installation requirement. The word "planned" should be inserted in the definition for GCIR.<br>Response: The SDT agrees and have inserted the word "planned" in the definition.<br><br>MOD-28 and MOD-029<br>The definitions for Area interchange Methodology and Rated System Path Methodology seem to be woefully inadequate – the "determination via simulation" explanation for the methodologies is pretty meaningless by itself – these should either be explained properly or be removed from the standards as "definitions" or could be added to the MOD-001 definition list. |

| Commenter | 2. Comments on Definitions |
|---|---|
| | Response: The drafting team has modified the definitions of Area Interchange Methodology and Rated System Path Methodology. The following sentence was added in MOD-028, "Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis." The following sentence was added in MOD-029, "Under the Rated System Path Methodology, and TTC results are generally reported as specific transmission path capabilities."<br><br>MOD-030<br><br>Is the Flowgate Methodology definition needed. If it is, shouldn't it simply be the method used to determine key facilities for selling transmission service? The current definition at a minimum needs to consider IROL as potential TFC instead of just system facilities.<br><br>Response: The SDT believes the definition is required, and has modified the definition to read as follows: Flowgate Methodology: The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on facility ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs are used to determine Available Transmission Capability (ATC).<br><br>The Flowgate definition should add "monitored transmission" in front of Facilities. A generator is also a facility but is not included as part of a flowgate definition. Also, bullet one should start with: "Designated paths on…" It is not a point.<br><br>Response: The SDT has modified the definition to read as follows: Flowgate: 1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.<br><br>The definition of PTDF also needs to be modified – it could be modified to read: "In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer."<br><br>Response: The SDT has modified the definition to read as follows: Power Transfer Distribution Factor (PTDF): In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer.<br><br>The definition of OTDF also needs to be modified – it could be modified to read: "In the post-contingency |

| Commenter | 2. Comments on Definitions |
|---|---|
| | configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more transmission facility element removed from service (outaged).” This is to ensure that PTDF is not confused with Generator Transfer Distribution Function (GTDF), as a generator is also a facility.<br>Response: The SDT has modified the definition to read as follows: Outage Transfer Distribution Factor (OTDF): In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged). |
| Response: | |
| ISO/RTO Council (IRC) | MOD-004<br>CBM is intended to be used for accessing generation from external sources to meet the LSE’s PLANNED capacity installation requirement. The word “planned” should be inserted in the definition for GCIR.<br>Response: The SDT agrees and have inserted the word “planned” in the definition.<br>MOD-030<br>Total Flowgate Capability does not consider that an IROL may be a limit.<br>Response: TFC does account for SOLs, and all IROLs are by definition also SOLs.<br>Is the Flowgate Methodology definition needed. If it is, shouldn’t it simply be the method used to determine key facilities for selling transmission service? The current definition at a minimum needs to consider IROL as potential TFC instead of just system facilities.<br>Response: The SDT believes the definition is required, and has modified the definition to read as follows: Flowgate Methodology: The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on facility ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs are used to determine Available Transmission Capability (ATC).<br>The Flowgate definition should strike the word monitored and add transmission in front of Facilities. The NERC Glossary of Terms gives a generator as an example of Facility and the current definition would then allow a generator to define a flowgate. Also bullet one should start with: A designated set of transmission facilities. It is not a point.<br>Response: The SDT has modified the definition to read as follows: Flowgate: 1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System. |

| Commenter | 2. Comments on Definitions |
|---|---|
| | MOD-029<br><br>The SRC notes that Order 890, P. 212 requires that the NERC Drafting Team address "counterflows" but does not provide direction as to the meaning of that term. As the term is often used interchangeably to mean actual flows of energy, scheduling of energy or reservations of transmission for possible scheduling of energy, the Team suggests that the NERC ATC Drafting Team clarify the meaning of the term as well as how it integrates into each proposed standard. Specifically, the NERC Drafting Team should clarify such items as: 1) is it a flow, a schedule or a reservation, 2) does it change characteristics based on the time frame examined (E.g. is it a reservation before it becomes a schedule?), 3) is it uni-directional or bi-directional. The term is used in numerous calculations but as presented is too vague to calculate rendering the formula opaque.<br><br>Response: The drafting team has modified the approach to counterflow in the standards based on the comments provided. The default values were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 to include more detail regarding how the TSP handles counterflows. With this approach we do not believe that a definition of counterflow is required. |
| Response: Please see in-line responses. | |
| Manitoba Hydro | |
| MidAmerican Energy Electric Trading | |
| Midwest ISO | |
| Modesto Irrigation District | MID supports the comments submitted by SMUD on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| MRO | a. The Posted Path definition in MOD-001-1 that indicates it includes any "Balancing Authority to Balancing Authority interconnection" and then R1 of the standard says ATC must "select one ATC methodology… for each Posted Path" and then R2 states that the TSP "shall calculate ATC values…using the ATC methodologies." As a result, the TSP must calculate ATCs and post those ATCs and all the Posted Paths. Many of these BA to BA paths are not useful paths to post either for commercial or reliability reasons. Therefore the language in the definition or the requirements should clarify that the definition provides the items such as any BA to BA path, path on which there has been curtailment, etc. that may qualify for posting or else the requirements should be changed to indicate that postings are not developed for all such paths but are developed for those paths that such postings are required for commercial and/or reliability reasons.<br><br>b. Presuming that changes are made per our comment 2.a. so that the Posted Path definition is only including items that are eligible for Posted Path and does not include items that must be posted, we note that the Posted Path definition in MOD-001-1 does not cover all the instances of a posted path in that there are flowgates that should be set up for reliability purposes to cover a system constraint that is not properly represented in the transmission service request evaluation process and is not covered by the three items listed. Service may not have been denied, curtailed, or interrupted yet due to the constraint because the facilities were not included in a flow gate. The MRO |

| Commenter | 2. Comments on Definitions |
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| | recommends that the following be included as an item in the definition "4) Any flowgate."<br><br>Posted Path Definition: The MRO asks the SDT to consider adding some language onto the end of Item (2) to qualify the statement. Something like "…and for which congestion is expected to occur." This is needed because it could have been an unusual operating condition (multiple generator/line outages) that caused the curtailment and that condition is not expected to occur again. |
| Response: A new term, ATC Path, has been defined for use in the NERC standards to avoid conflicting with a term presently defined by FERC. It is defined as "Any combination of Point of Receipt and Point of Delivery for which ATC is calculated." | |
| New Brunswick System Operator | |
| NorthWestern Energy (NWMT) | In MOD-001, Posted Path is included in defined terms. This is a duplication of "Posted path" in 18 CFR Part 37.6 (b)(1)(i). Suggest that throughout these MODs, replace the term Posted Path with "paths required to be posted" or "paths requiring posting" or "paths for which ATC is calculated". |
| Response: A new term, ATC Path, has been defined for use in the NERC standards to avoid conflicting with a term presently defined by FERC. It is defined as "Any combination of Point of Receipt and Point of Delivery for which ATC is calculated." | |
| NPCC Regional Standards Committee | |
| NYISO | The NYISO supports the comments that the Northeast Power Coordinating Council ("NPCC") has submitted in response to this question.<br><br>Except as noted by the NPCC, all of the proposed definitions appear to be correct, assuming that NERC shares the NYISO's view that the definitions are sufficiently flexible to accommodate transmission providers that have obtained waivers from various FERC ATC and OASIS requirements and that do not offer transmission service based on physical reservations. As is discussed in more detail in response to Question Five, the NYISO, with FERC's approval, does not offer the kind of physical reservation transmission service that is the primary focus of Order Nos. 888 and 890. Nevertheless, the NYISO believes that its form of financial reservation transmission service fits within the framework of NERC's proposed definitions and standards.<br><br>It is very important to the NYISO that the proposed definition of "Existing Transmission Commitments" ("ETC") in MOD-028 and MOD-029 be interpreted flexibly. Many of the variables in the proposed ETC algorithm will not be applicable (or will always have a value of zero) in the NYISO's case. Specifically, the NYISO does not reserve capacity to serve native load growth, its customers do not hold physical reservations of point to point transmission service and have never taken Network Integration Transmission Service. On the other hand, the most important input into the NYISO's ATC calculations is "Transmission Flow Utilization," which is based on the security constrained network powerflow solutions determined by the NYISO's day-ahead and real-time market software. It appears that the OS(F) variable in the proposed ETC algorithm is broad enough for the NYISO to include Transmission Flow Utilization information when calculating ETC (and thus ATC). To the extent necessary, the NYISO will provide additional information concerning its market software's computation of Transmission Flow Utilization and its role in the ETC calculation in the NYISO's Available Transfer Capability Implementation Document |

| Commenter | 2. Comments on Definitions |
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| | ("ATCID").<br><br>If NERC disagrees with this interpretation then the NYISO requests that the MOD-028 and MOD-029 definition of ETC (and/or OS(F)) be revised to expressly allow ISO/RTO market software results, such as the NYISO's Transmission Flow Utilization information, to be considered in ETC calculations. Otherwise, the NYISO's existing method of calculating and posting ATC using market software outputs, which is a core feature of its FERC-approved market design, would be in conflict with NERC's standard. Additional information on the NYISO's financial reservation system is provided in the response to Question Five, below.<br><br>Finally, the definition of the OS(F) variable in the MOD-29 description of the ETC algorithm (at R9) may be slightly narrower in scope than the MOD-28 version because the MOD-29 definition does not include the language referencing "any other firm adjustments to reflect impacts on other Posted Paths as described in the ATCID" that is found in MOD-28. Because it is not clear why the two OS(F) definitions should be different, the NYISO asks that NERC revise the MOD-29 version to conform to the MOD-28 version.<br>Response: The SDT has modified the standard to allow for inclusion of details in the ATCID. However, path interactions as described in MOD-028's definition of $OS_f$ are addressed in the determination of TTC in MOD-029, and adding such language here is inappropriate. |
| Response: We generally agree with your comments, and believe that you should be able to comply with the requirements.<br>Please see additional in-line responses. | |
| PacifiCorp | The WECC MIC MIS ATC Drafting Team suggests in its comments that the NERC ATC Drafting Team clarify the meaning of the term "counterflows." PacifiCorp suggests that with regard to this comment, any changes to clarify the term "counterflows" should not undermine the flexibility allowed in the definition of the term "counter-schedules" in MOD-029 that states "Counter-schedules are adjustments to firm/non-firm Available Transfer Capability as determined by the Transmission Service Provider and described in its Available Transfer Capability Implementation Document. |
| Response: The drafting team has modified the approach to counterflow in the standards based on the comments provided. The default values were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 to include more detail regarding how the TSP handles counterflows. With this approach we do not believe that a definition of counterflow is required. By making this change, the drafting team no longer believes it necessary to have a separate definition for counter-schedules. | |
| PJM Interconnection LLC | GCIR should observe the practice of multiple LSEs aggregating and agreeing with other entities such as ISOs to determine such requirements. The GCIR for grouped LSEs would differ from the sum of the individual LSEs. In such a case CBM will be determined for the aggregate and processes/ procedures for individual LSEs to request CBM will not be observed. |
| Response: The SDT agrees that an aggregation of LSEs to determine an aggregated GCIR would be more efficient than separate LSE calculations for the same "electrical area". However, the SDT cannot mandate aggregation or limit a genuine LSE request. The standard does not preclude aggregation. The drafting team has also added a new definition for "Planned Resource Sharing Group(PRSG)" for those LSEs who have jointly agreed to meet their resource adequacy requirements . The SDT has also revised the standard to make it clearer regarding requirements of PRSGs. | |

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| Progress Energy, Carolinas | |
| Public Service Commission of SC | |
| Public Utility District #2 of Grant County, Washington | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Puget Sound Energy | In MOD-001, Posted Path is included in defined terms. This is a duplication of “Posted path” in 18 CFR Part 37.6 (b)(1)(i). Suggest that throughout these MODs, replace the term Posted Path with “paths required to be posted” or “paths requiring posting” or “paths for which ATC is calculated”. |
| Response: The Drafting Team believes that, for reliability, where ATC must be calculated is not captured completely by the FERC definition of Posted Path. As such, a new term, ATC Path, has been defined for use in the NERC standards. | |
| Salmon River Electric Cooperative | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Salt River Project | SRP supports those definitions provided in MOD-4, MOD-08 and MOD-29. SRP does not elect to comment on defined terms offered in MOD-28 or MOD-30.<br><br>MOD-001-01 The term Posted Path should not be defined in the standard. Defining Posted Path conflicts with the Background Information provided by the Standards Drafting Team and duplicates FERC regulations in 18CFR37.6. Specifically, the request for comments stated<br><br>“…Major Changes include-removed all requirements to make data or information ‘publicly available’ – the drafting team has been working cooperatively with NAESB and all posting requirements will be addressed in NAESB business practices.”<br><br>Therefore, because Postings are not being addressed and because Posted Path is defined in CFR37.6, the term Posted Path should not be defined in a NERC standard and should be referenced as a FERC term. |
| Response: A new term, ATC Path, has been defined for use in the NERC standards to avoid conflicting with a term presently defined by FERC. It is defined as “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated.” | |
| Santee Cooper | Recommend changing Posted Path 1) definition to read “Any Balancing Authority to Balancing Authority direct interconnection”. Add the word direct. |
| Response: A new term, ATC Path, has been defined for use in the NERC standards to avoid conflicting with a term presently defined by FERC. It is defined as “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated.” | |
| SERC ATCWG | MOD-0028, 029 and 030 refer to “postback”. There is not a definition in the NERC Glossary for this term. Please consider the following as the definition: “Postbacks are increases to ATC values resulting from transmission service being redirected by customers to other paths or from transmission service not being scheduled by customers during that period, as defined in Business Practices.” |
| Response: The SDT has clarified the term post back by incorporating the following definition: “Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.” Note that | |

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| NAESB will be defining specifically what values should be considered when determining Postbacks. | |
| Sierra Pacific Resources Transmission | MOD-001 "Posted Path" is included in defined terms. Because this is a duplication of "Posted Path" in 18 CFR Part 37.6 (b)(1)(i) it is suggested "paths where ATC is calculated" or similar definition be used.<br>Response: A new term, ATC Path, has been defined for use in the NERC standards to avoid conflicting with a term presently defined by FERC. It is defined as "Any combination of Point of Receipt and Point of Delivery for which ATC is calculated."<br>"Counterflows" appears to be used interchangeably to mean actual flows of energy, scheduling of energy or reservations of transmission for possible scheduling of energy. The SPR Companies suggest the NERC ATC Drafting Team clarify the meaning of the term as well as how it integrates into each proposed standard. Specifically, the NERC Team should clarify such items as: 1) is it a flow, a schedule or a reservation, 2) does it change characteristics based on the time frame examined (E.g. is it a reservation before it becomes a schedule?), 3) is it uni-directional or bi-directional. The term is used in numerous calculations but as presented is too vague to calculate in the formula.<br>Response: The drafting team has modified the approach to counterflow in the standards based on the comments provided. The default values were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 to include more detail regarding how the TSP handles counterflows. With this approach we do not believe that a definition of counterflow is required. |
| Response: Please see in-line responses. | |
| Snohomish PUD | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| The Southeast Coalition | The term "Postback" is not standard in the industry and has not been defined in the Standard. A definition for this term should be included in the Standard.<br>Response: The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks.<br>Requirements R6.2, R6.3, and R6.4 of MOD-030 refer to transmission service "expected to be scheduled". Is this term being used to refer to reservations that are frequently scheduled as opposed to those that are infrequently scheduled? Please clarify.<br>Response: Although the frequency of the reservation being scheduled can influence your expectations, in some instances an infrequently scheduled reservation could be expected to be scheduled. For example, you may use seasonal or historical trends to guide expectations. |
| Response: See in-line responses above. | |

<table>
<tr><th>Commenter</th><th>2. Comments on Definitions</th></tr>
<tr><td>Southern Company Transmission</td><td>MOD-028-1.<br><br>Suggest adding the following language to the end of the “Area Interchange Methodology” definition: “Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis, as opposed to being based upon a specific Transmission Path.”  Please see 1995 TTC Reference Document Reporting of transfer Capability on pages A-6.<br><br>Response: The drafting team has modified the language in the standard to include these concepts.<br><br>MOD-029-1.<br><br>Suggest adding the following language to the end of the “Rated System Path Methodology” definition: “Under the Rated System Path Methodology, TTC results are reported with a focus toward specific transmission path capabilities.”  Please see 1995 TTC Reference Document Reporting of transfer Capability on pages A-7.<br><br>Response: The drafting team has modified the language in the standard to include these concepts.<br><br>MOD-030.<br><br>TFC is generally based upon ratings, not SOL.  Suggest the following language.<br><br>Total Flowgate Capability (TFC): The maximum flow capability on a Flowgate, not to exceed its thermal rating, or in the case of a proxy flowgate used to represent a specific operating constraint (such as a stability limit), not to exceed the associated System Operating Limit.<br><br>Response: The SDT has accepted your suggestion, with slight modification to remove the reference to “proxy” flowgates.  “The maximum flow capability on a Flowgate, not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), not to exceed the associated System Operating Limit.”</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>SPP</td><td>No comment.</td></tr>
<tr><td>Tacoma Power</td><td>Tacoma Power supports the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.</td></tr>
<tr><td colspan="2">Response: Please see responses to the WECC MIC MIS ATC Drafting Team.</td></tr>
<tr><td>Tri-State Generation and Transmission Association</td><td></td></tr>
<tr><td>WECC MIC MIS ATC TF Drafting Team</td><td>The Team and those listed above support those definitions provided in MOD-01, MOD-4, and MOD-08.  The Team and those listed above do not elect to comment on defined terms offered in MOD-28.<br><br>The Team and those listed above note that Order 890, P. 212 requires that the NERC Drafting Team address “counterflows” but does not provide direction as to the meaning of that term.  As the term is often used interchangeably to mean actual flows of energy, scheduling of energy or reservations of transmission for possible scheduling of energy, the Team and those listed above suggest that the NERC ATC Drafting Team clarify the</td></tr>
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| Commenter | 2. Comments on Definitions |
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| | meaning of the term as well as how it integrates into each proposed standard. Specifically, the NERC Team should clarify such items as: 1) is it a flow, a schedule or a reservation, 2) does it change characteristics based on the time frame examined (E.g. is it a reservation before it becomes a schedule?), 3) is it uni-directional or bi-directional. The term is used in numerous calculations but as presented is too vague to calculate rendering the formula opaque. |
| Response: The drafting team has modified the approach to counterflow in the standards based on the comments provided. The default values were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 to include more detail regarding how the TSP handles counterflows. With this approach we do not believe that a definition of counterflow is required. By making this change, the drafting team no longer believes it necessary to have a separate definition for counter-schedules. | |
| WestConnect Transfer Capability Workgroup | The Team agrees with the WECC's Comment that the NERC ATC Drafting team should clarify the meaning of the term counterflows. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Western Area Power Administration – RMR | The Team supports those definitions provided in MOD-01, MOD-4, and MOD-08. The Team does not elect to comment on defined terms offered in MOD-28.<br><br>The Team notes that Order 890, P. 212 requires that the NERC Drafting Team address "counterflows" but does not provide direction as to the meaning of that term. As the term is often used interchangeably to mean actual flows of energy, scheduling of energy or reservations of transmission for possible scheduling of energy, the Team suggests that the NERC ATC Drafting Team clarify the meaning of the term as well as how it integrates into each proposed standard. Specifically, the NERC Team should clarify such items as: 1) is it a flow, a schedule or a reservation, 2) does it change characteristics based on the time frame examined (E.g. is it a reservation before it becomes a schedule?), 3) is it uni-directional or bi-directional. The term is used in numerous calculations but as presented is too vague to calculate rendering the formula opaque. |
| Response: The drafting team has modified the approach to counterflow in the standards based on the comments provided. The default values were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 to include more detail regarding how the TSP handles counterflows. With this approach we do not believe that a definition of counterflow is required. By making this change, the drafting team no longer believes it necessary to have a separate definition for counter-schedules. | |

**3. If there is a requirement in any of the proposed standards that you believe is technically incorrect, please identify the standard and requirement and identify what is incorrect. If possible, provide alternate language that you believe would make the requirement technically correct.**

**Summary Consideration:** Several entities expressed concern regarding the requirement that CBM be granted prior to TSRs when capacity became avail able. The drafting team discussed this issue at length, and determined that both methods (holding capacity for un-granted CBM requests, putting CBM requests into a queue for processing) were acceptable. Accordingly the SDT has changed the standard to allow entities to take either approach, provided they document the manner used in their ATCID.

The drafting team modified the approach to counterflow in the standards based on the comments provided. The default values were removed and a requirement for the ATCID to provide detail regarding how the TSP handles counterflows.

The drafting team modified many of the requirements in MOD-030 related to the thresholds used to determine if the impacts of other neighboring systems such that they only have to be used if they're impact is greater than what is used in the Transmission Service Provider's Interconnection-wide congestion management procedure. This ensures that in general, service is not sold on a basis that is more liberal than that which is used to curtail service. TSPs may use thresholds lower than that specified if desired.

Many entities expressed concern that the monthly updates related to changes in CBM were excessive. The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. The standard has been modified to clarify that entities must update their CBM at least once a month if it changes, but that determination may be through a recalculation or through a simple adjustment (e.g., a addition or subtraction, based on contracts or other drivers).

Some entities expressed a misunderstanding of the relationship between Violation Severity Levels and Violation Risk Factors. VSLs are related to the amount of deviation from the standard. VRFs are related to the impact on reliability. An analogous situation would be grades in school; Severity Levels are similar to the "grade" (A, B, C, D, and F) and the Risk Factor is similar to the "type of grade" (homework, quiz, research paper, term paper, final exam).

Many entities expressed concern regarding the amount of time allowed to comply with a request for information. In general, these requirements were extended to allow thirty days.

Timing and calculation requirements for ATC, TTC, AFC, and TFC were modified to reflect provider's comments. MOD-001 now requires recalculation of ATC on a fixed schedule unless none of the elements used in the ATC formulas have changed. AFC requires recalculation on a fixed schedule.

Many entities expressed a desire for more justification and consistency in the requirements related to the scope of the model used in determining ATC. The drafting team made MOD-030 and MOD-028 consistent with regard to size and the use of equivalences. MOD-029 was modified to incorporate a local review process.

With regard to the Violation Risk Factors, several entities requested either many or all requirements be set to Low. The drafting team discussed the requested changes at length, but was ultimately unable to come to consensus sufficient enough to establish the required supermajority vote to change the VRFs. NERC defines that requirement with a Violation Risk Factor of Lower is one that "if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system." The SDT does believe that there are many requirements in these standards to which this VRF should apply, but there also are many that can have a more significant impact than this.

Many entities expressed disagreement with the SDT with regard to the assignment of responsibility to functional entities. The SDT referred entities to the functional model for clarification. However, the SDT notes that the functional model is not always clear, and in some cases, the SDT's interpretation may be different that that of other entities. The SDT notes that the functional model is currently being reviewed and updated.

Many entities expressed confusion with regard to the difference between NERC and NAESB responsibilities. The SDT clarified that items related to the customer interface, such as the posting of documents on OASIS or public disclosure of information to the marketplace, were the responsibility of NAESB. Items related to the determination of information related to reliability coordination are within the scope of NERC.

NERC defines that a requirement with a Violation Risk Factor of Medium is one that "if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures." The SDT believes that several of the requirements in these standards, if not met, can directly affect the electrical state or capability of the bulk electric system. These have been assigned a VRF of medium.

Some entities expressed concern with a MOD-001 R10 requiring the provision of data without clarifying the owner of that data. The requirement was modified to be clear that only provision of the entities own data is required.

Many entities expressed concern that the requirement to use "peak" load forecasts was too prescriptive. The drafting team removed the requirement to use only "peak" load forecasts.

The SDT made other minor corrections and clarifications as needed.

| Commenter | 3. Comments on Requirements |
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| Alberta Electric System Operator | |
| Ameren Services | MOD-004-1<br><br>- R4.2. This is a fundamental mathematical analytical dichotomy. The CBM component is based on probabilistic LOLE/LOLP style analyses that look at aggregate probability loss. The reserve sharing component of TRM is deterministic. It is imprudent to combine these as they are not derived from the same methodology except in the rare case where the generation is sufficiently constrained that the only resulting generation left after CBM event is the reserve sharing generation.<br><br>Response: The drafting team did not mandate that TRM be deterministic, or that CBM be probabilistic. However, the standard does require that they not be additive such that double counting occurs. FERC order 890 paragraphs 1069, 1078 and 1082 all make reference to not allowing the use of CBM and TRM "for the same purposes" From paragraph 1078:"We continue to believe this Reliability Standard should be modified to include a provision ensuring that CBM, TRM and ETC cannot be used for the same purpose, such as loss of the identical generating unit." Having a portion of TRM for reserve sharing would constitute the "loss of the identical generating unit" as is covered in setting aside CBM for the loss of multiple units. Hence, only the portion of TRM used for reserve sharing must be subtracted from CBM<br><br>- R4.2.2. Since AFC is determined from CBM, CBM for each Flowgate should not be dependent on AFC. CBM can be big enough to drive AFC to zero or negative. This simply means that resource adequacy criteria can't be met, and no capacity will be available on that Flowgate (which is what the original wording of this requirement was trying to do |

| Commenter | 3. Comments on Requirements |
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| | anyway). Therefore CBM should not be set to AFC, it should be left at whatever value was calculated. This concept applies to R4.2.1 and R5.2 as well.<br><br>Response: The standard has been edited to allow the TSP to decide how to address this concern and requires they document their decision in their CBMID.<br><br>R4.3 and R5.3 Not necessary. Refer to R4.2.2 for explanation.<br><br>Response: These sections have been removed and the standard has been edited to allow the TSP to decide how to address this concern and requires they document their decision in their CBMID. |
| Response: Please see in-line responses. | |
| American Transmission Company | |
| Arizona Public Service Co. | Arizona Public Service Co. is in agreement with the WestConnect Comments and in general agreement with the WECC Comments.<br><br>Response: Please see responses to WestConnect and the WECC MIC MIS ATC Drafting Team.<br><br>In addition the Arizona Public Service Co. adds the following comment.<br><br>MOD-001<br><br>The use of Counter Schedules to create firm ATC is of concern to APS. This practice could result in unreliable conditions to the interconnection if the counter flows do not occur. Due to the reliability concerns there should be a requirement for the Transmission Provider to provide documentation of actions that it will take if the Counter Flows do not occur.<br><br>Response: The standard does not require the creation of firm ATC from counterflows or counterschedules; rather, it only allows for the creation of those counterflows or counterschedules if included in the provider's ATCID. The Drafting Team has removed R4 and R5 (the "default" counterflow requirements) to further clarify that use of counterflows/counterschedules is not required. |
| Response: Please see in-line responses. | |
| Avista Corporation | |
| Bonneville Power Administration | MOD-001<br><br>- i.R1 and R2 – "time periods" should be replaced with "time horizons"<br><br>Response: The drafting team eliminated the term "horizons" to eliminate confusion with other Time Horizons (e.g., those used by compliance). |

| Commenter | 3. Comments on Requirements |
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| | - ii. R3.2 – "counter-schedules" should be deleted and "counterflows" should be capitalized with the definition supplied above [Counterflow: the impact of schedules, reservations, or actual energy flows in the direction opposite to the constraint<br><br>Response: The drafting team has modified the approach to counterflow in the standards based on the comments provided. The default values were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 to include more detail regarding how the TSP handles counterflows. With this approach we do not believe that a definition of counterflow is required.<br><br>- iii. R3.3 – BPA suggests removal of this requirement, as it would require extensive modification to existing databases without serving a great need.<br><br>Response: The Drafting Team has modified the requirement to require a list of Transmission Operators from which the Transmission Service Provider receives data for use in ATC calculations instead of requiring this information for each facility.<br><br>- iv. R4 and R5 – should be cut from MOD-001 and placed in MOD-028, -029, and -030<br><br>Response: R4 and R5 have been removed and a description has been required in the ATCID per R3 of MOD-001.<br><br>- v. R10 – The wording is confusing and should be modified to the following: "…current versions of the following data, limited to that data requested, in electronic format…"<br><br>Response: We have modified the language slightly to be clearer. Note that the provider must only make available the data as requested (i.e., if the data was not requested, it doesn't need to be made available)<br><br>- vi. R10.2 – "Peak" should be deleted, as non-peak load forecasts may be used in ATC calculations<br><br>We have deleted the word "peak" per your suggestion.<br><br>- vii. R10.3 – BPA requests that the term "Block dispatch" be defined<br><br>Response: We have added the following definition: BLOCK DISPATCH – A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).<br><br>- viii. R10.4 – Should be modified to the following, to be less vague and more consistent with the pro-forma OATT: "Aggregated capacity encumbered for Network Integration Transmission Service and Secondary Service" |

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| | Response: The Drafting Team has changed this requirement using similar language that is consistent with that used in MOD-028 and MOD-029.<br><br>-ix. R10.6 – Should be modified to the following, to allow for the inclusion of Grandfathered service or other statutory obligations that have not been contracted for: "Aggregated capacity encumbered for Grandfathered obligations"<br>Response: The Drafting Team has changed this requirement using "set aside" instead of "encumbered".<br>-x. R10.13 – It appears as though the following is missing from the last right parenthesis: "(TRM"<br>Response: The SDT has modified the standard to address this typographical error.<br>b. MOD-004<br>- i. R1 – Should have a fourth sub-requirement added to explain that if there is insufficient capacity available to satisfy all requests for CBM, the Transmission Service Provider shall explain in its CBMID how allocation of CBM will occur<br>Response: Since CBM is a margin, and not a reservation, there is no need to allocate. If there is insufficient capacity, then either the TSP will set aside what is available or allow the ATC/AFC to become negative. (the new R4.2 and R4.3) The only time this would be required would be if multiple entities who requested to schedule using CBM above what the system could accommodate at the same time. At that time, their use would need to be pro-rata adjusted (possibly through TLR).<br><br>- ii. R2 – Should be modified to the following: "…CBMID to the Transmission Operator, adjacent Transmission Service Provider…"<br>Response: The SDT has modified this language to address your concerns.<br>- iii. R8 – Should be modified to the following: "…set aside as CBM unless affected by a declared NERC Energy Emergency Alert (EEA) 2 or higher"<br>Response: The SDT has modified this language to address your concerns.<br>c. MOD-029<br>- i. R1.4 – "Non-regulating" should not be capitalized<br>Response: The SDT has modified the standard to address this typographical error.<br>- ii. R1.6 – "peak" should be deleted, as non-peak load forecasts may be used in TTC calculations<br>Response: The SDT has removed the word "peak" to address your concerns.<br>- iii. R1.12 – "ACTID" should be changed to "ATCID"<br>Response: The SDT has modified the standard to address this typographical error. |

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| | - iv. R2.2 – There appears to be a potential discrepancy between this requirement and other reliability requirements for establishing System Operating Limits.<br><br>Response: The drafting team does not believe that there is a discrepancy between this requirement and any other reliability requirement for establishing System Operating Limits. Requirement R3 address' the relationship between the requirements in this standard and System Operating Limits. The new wording for R3 is as follows: The Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit for that ATC Path. We believe R3 now addresses the concern expressed.<br><br>- v. R2.3 – "R1.2.1" should be changed to "R2.1"<br><br>Response: The SDT has modified the standard to address this typographical error.<br><br>- vi. R5 – "reserved" should be changed to "encumbered" in the description of NL, GF, and OS, as these obligations may not have been reserved via an OASIS transaction – Additionally, the "Firm Transmission Service" in the description of GF should not be capitalized<br><br>Response: To address your concern, the SDT has changed the standard to use the term "set aside."<br><br>- vii. R6 – "reserved" should be changed to "encumbered" in the description of GF and OS, as these obligations may not have been reserved via an OASIS transaction – Additionally, the "Transmission Service" in the description of GF should not be capitalized<br><br>Response: To address your concern, the SDT has changed the standard to use the term "set aside."<br><br>- viii. R7 and R8 – "Counter-schedules" should be changed to "Counterflows" with the definition supplied above [Counterflow: the impact of schedules, reservations, or actual flows of energy in the direction opposite to the constraint]<br><br>Response: The drafting team has modified the approach to counterflow in the standards based on the comments provided. The default values were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 to include more detail regarding how the TSP handles counterflows. With this approach we do not believe that a definition of counterflow is required.<br><br>- ix. R8 – "non-" should be deleted from the description of ETC<br><br>Response: The SDT has modified the standard to address this typographical error.<br><br>d. MOD-030<br><br>- i. R2.1 – Delete "for" after "Flowgates"<br><br>Response: The SDT has modified the standard to address this typographical error.<br><br>- ii. R2.1.1 – BPA suggests the following clarification to this requirement, to avoid posting unnecessary data: "Any Facility within the Transmission Operator's area based on thermal, stability or voltage limits is a Flowgate if such limits |

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| | reduce transfer capability on a Posted Path<br><br>Response: The Standard Drafting Team agrees. This requirement has been changed to reflect a more reasonable scope.<br><br>- iii. MOD-001 allows an entity to select multiple methodologies to determine ATC. For example, an entity may elect to use Flowgates inside their affected area whereas they may also elect to use the Rated System Path Methodology at the interface of their affected area. Under this scenario, the applicable entity need not study Flowgates beyond the intercepting cut plane of its interface as the ATC at the interface falls not under MOD-030, but MOD-029. To prevent unneeded seams issues, the following rewrites are suggested:<br><br>1. R2.1.2 – All first Contingency transfer analyses from all adjacent Balancing Authority source sink combinations such that at a minimum the first three limiting Elements/Contingency combinations within the Transmission Operator's system are included as Flowgates, unless the interface between such adjacent Balancing Authorities is accounted for using the Rated System Path Methodology<br><br>2. If adopted, similar language should be applied to R3.5, R3.6, R5.1, R6.1, R6.3, R6.4, R7.2, and R7.4<br><br>Response: The SDT has modified the standard to ensure conflicts between the standards are minimized.<br><br>R6.1, R6.3, R6.4, R7.2, R7.4 have been addressed by adding the stipulation that impacts of other neighboring systems only have to be used if they're impact is greater than what is used in the regional congestion management procedure. This allows for sparse networks that do not get impacted by neighboring transactions to ignore them.<br><br>- iv. R4 – "Use" should not be capitalized.<br><br>Response: The SDT has modified the standard to address this typographical error.<br><br>Additionally, two sub-requirements should be added to allow for the modeling of impacts of Network Integration Transmission Service and Grandfathered service in the base AFC calculations.<br><br>Response: The drafting team feels that R6 and R7 allow for the impacts of Network Integration Transmission Service and Grandfathered service to be accounted for in the AFC calculations.<br><br>- v. R6.1 – "Firm Network" should be changed to "Network Integration Transmission Service" to be consistent with how this service is identified in the OATT<br><br>Response: The language has been changed to be consistent with the OATT.<br><br>- vi. R6.1.1.1, R6.1.2.1, R6.1.3.1, and R6.1.4.1 – "Peak" should be deleted, as non-peak load forecasts may be used in ETC calculations –<br><br>Response: The SDT agrees, and has eliminated the word "peak." |

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| | Additionally R6.1.3.1 is incorrectly identified as "R6.1.3.1.1"<br><br>Response: The SDT has modified the standard to address this typographical error.<br><br>- vii. R6.3 – The last sentence should be a separate requirement, similar to R7.3 – this would result in the final sentence of R6.3 becoming R6.4 and the current R6.4 becoming R6.5. The new R6.4 and R6.5 should also be modified to the following to accommodate Grandfathered service or other statutory obligations for which a contract does not exist or scheduling requirements are not in place: "The impact of any firm Grandfathered obligations expected to be utilized…"<br><br>Response: The SDT has modified the standard to address this typographical error. The SDT also incorporated the language suggested regarding "obligations" versus "contracts."<br><br>- viii. R7.3, and R7.4 – Each should have the word "contracts" replaced with "obligations" to accommodate GF service that does not hold a contract.<br><br>Response: The SDT agrees, and has replace contracts with obligations.<br><br>ix. R7 – A sub-requirement should be added to allow for the inclusion of the impacts of Network Integration Transmission Service and Secondary Service<br>Response: The SDT agreed, and has corrected this oversight. |
| Response: Please see in-line responses. | |
| British Columbia Transmission Corporation | 1. MOD-001-1, R3.3 - The word "Facility" should be replaced with "Posted Path".<br><br>Response: The Drafting Team changed the requirement so that neither term is necessary.<br><br>2. MOD-029-1, R1.6 - We suggest that the word "peak" be removed. Often maximum TTC occur at off-peak conditions when load near to the generation is lower.<br><br>Response: The SDT has removed the word "peak" to address your concerns. |
| Response: Please see in-line responses. | |
| Clearwater Power Company | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| ColumbiaGrid, Inc. | [Intentionally left blank.] |
| Consumers Power, Inc. | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |

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| Duke Energy | - MOD-001-1, R5.2 should say "approved Interchange Transaction Tags" instead of "schedules".<br><br>Response: This requirement has been removed.<br><br>- MOD-001-1, R9 should say "recalculate" rather than "update".<br><br>Response: The Drafting Team has modified the language and has included this change.<br><br>- MOD-001-1, R10 should allow 30 days instead of 14 days to make data available after a request, since setting up the required data exchange protocols will be time-consuming.<br><br>Response: The Drafting Team has incorporated this change.<br><br>MOD-004-1, R3.1.1.2 should be revised to require a monthly GCIR value for each month during the current year and the following two years for each Balancing Authority or Posted Path.<br><br>Response: The drafting team has set the requirement to 24 months.<br><br>MOD-004-1, R3.2 should be revised as follows: Pursuant to the frequency established in the Transmission Service Provider's CBMID, update the request provided per 3.1 to reflect any changes that alter future needs for CBM or indicate that no change is needed.<br><br>Response: The drafting team has provided clarifying language in R3.2 to address your concerns.<br><br>MOD-004-1 Requirements:<br><br>R3.2 At least every thirty-one days, update the request provided per R3.1 to reflect any changes that alter future needs for CBM or indicate that no change is needed.<br><br>M4. The Load-Serving Entity that wants CBM shall provide dated copies of its updated CBM requests as evidence that it has updated its CBM request or confirmed no update was needed at least every thirty-one days, per R3.2 (R3).<br><br>VSLs tied to this measure increase in severity due to change in GCIR. (e.g., Moderate VSL is tied to failure to update and Generation Capability Import Requirement had changed by more than 20MW or 10%, whichever is smaller, and not more than 30MW or 20%, whichever is smaller. Severe VSL is tied to failure to update and Generation Capability Import Requirement had changed by more than 40MW or 30%, whichever is smaller.)<br><br>Duke Comments:<br><br>1. There is no basis in Order 890 for this requirement of updating every 31 days. This creates an unnecessary administrative burden on the Transmission Provider, the Transmission Planner, and the Load-Serving Entities.<br><br>Response: The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. The standard is requiring that entities update their CBM at least once a month if it changes to ensure that no unneeded CBM is still being held back from the market. |

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| | 2. The VSLs are too severe; If an LSE's GCIR is 5 MW when the initial request was submitted and it later rose to 7 MW (40% change), the LSE would be subject to penalty based on SEVERE VSL. Severity should reflect magnitudes of MW values that have a meaningful impact on reliability, not arbitrarily defined calculations.<br><br>Response: The SDT understands the concern expressed, but believes it to be based on a misunderstanding of the relationship between Violation Severity Levels and Violation Risk Factors. VSLs are related to the amount of deviation from the standard. VRFs are related to the impact on reliability. In this case (R3), the Violation Risk Factor is "lower," indicating there is a low impact on reliability. This would result is a range of smaller Sanctions for violations of this requirement (based on the June 7, 2007, Sanction Guidelines, sanctions would range between $1,000 and $25,000 for this violation; additionally, since the Time Horizon is Operations Planning, sanctions would likely be on the lower side of this range). An analogous situation would be grades in school; Severity Levels are similar to the "grade" (A, B, C, D, and F) and the Risk Factor is similar to the "type of grade" (homework, quiz, research paper, term paper, final exam).<br><br>3. The requirements and measure should be changed so that it more accurately reflects the VSLs and should require updating the CBM request if GCIR changes by more than xx MW.<br><br>Response: The SDT believes the requests should be accurate. Any case where the number is not accurate is a violation; how far off the number was from reality defines the grossness of the violation.<br><br>4. The only required timing update should be annual updates in order to provide requirements for the new 10th year.<br><br>Response: The SDT disagrees for the reasons described above.<br><br>MOD-004-1 Requirements:<br><br>R3. A Load-Serving Entity (or group of Load-Serving Entities with an aggregated need for CBM) that wants Transfer Capability to be set aside in the form of CBM shall:<br><br>R6. Within five days of the determination of CBM as described in R4 or R5, the Transmission Service Provider shall provide each Load-Serving Entity (or group of Load-Serving Entities with an aggregated need for CBM) that requested CBM and the Balancing Authority hosting its (their) load with a report that includes: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]<br><br>R6.1. The total amount of CBM for each Posted Path or Flowgate on the Transmission Service Provider's system in each of the months or years specified in the original request. If less than the sum of all requests was established as the CBM for any period:<br><br>- For each Posted Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the months and years specified in the original request |

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| | - The option to request a system impact study.<br><br>Duke Comments:<br><br>1. How shall penalties be assessed for a group of Load-Serving Entities? Is each LSE subject to the full penalty or is the penalty allocated to each LSE in the group? If allocated, how is that done? Are there NERC rules to address this situation?<br><br>Response: We have incorporated the use of a Planned Resource Sharing Group (PRSG) A PRSG will need to register as a Joint Registration Organization and it would be the assessed entity. How the PRSG handles it from that point is outside the scope of this standard.<br><br>2. We foresee difficulties in groups of LSEs making a request for a system impact study and think this option should be removed. CBM is a margin and not a transmission service as defined by FERC, so there is no clearly defined mechanism for charging customers for such upgrades. The introduction of this option creates significant controversy which may delay approval of the standard.<br><br>Response: The drafting team has changed this language to be clearer about the obligations of the TSP.<br><br>Typo in R2 – Replace CBID with CBMID “R2. The Transmission Service Provider shall make available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator within seven days of a change.”<br><br>Response: The SDT has addressed this typographical error.<br><br><br>MOD-004-1 Requirements: Evaluation deadlines do not consider other received requests<br><br>R4. Within fourteen calendar days of receiving a request or change to a request for CBM that meets the requirements defined in R3.1, the Transmission Service Provider shall set the CBM for the months requested…<br><br>R5. Within sixty calendar days of receiving a request or change to a request for CBM that meets the requirements defined in R3.1, the Transmission Planner shall set the CBM for the years requested…<br><br>R4 High VSL: The Transmission Service Provider set CBM for the months requested as described in R3.1.1.2 more than 14, but not more than 30, days after receiving a request for CBM.<br><br>R4 Severe VSL: The Transmission Service Provider set CBM for the months requested as described in R3.1.1.2 more than 30 days after receiving a request for CBM.<br><br>R5 High VSL: The Transmission Planner set CBM for the years requested as described in R3.1.1.3 more than 60, but not more than 120, days after receiving a request for CBM.<br><br>R5 Severe VSL: The Transmission Planner set CBM for the years requested as described in R3.1.1.3 more than 120 days after receiving a request for CBM.<br><br>Duke Comments:<br><br>CBM requests should be evaluated in queue order along with other Firm service requests and all rules that apply to evaluation timing of firm service request should apply to CBM requests. Monthly CBM requests should be have the |

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| | same timing requirements as Monthly Firm Point-to-Point requests and Yearly CBM requests should have the same timing requirements as Yearly Firm Point-to-Point requests. Delays in processing CBM requests may legitimately be due to the need to fully process earlier queued requests but the NERC process does not make provisions for such delays. NAESB should revise these rules. Transmission Providers should not be subject to penalties for failure to evaluate on time by both NERC and NAESB rules.<br><br>Response: The standard has been modified to clarify that how the TSP handles the processing of CBM and TSRs will need to be described in their CBMID.<br><br>Modifying CBM after evaluations have been completed is not aligned with current request evaluation process and may cause billing issues<br><br>Response: The standard has been modified to remove conflicts with queuing to address your concern.<br><br>MOD-004-1 Requirements:<br><br>R4.3. If the sum of all CBM requests can not be met simultaneously, and during the evaluation of monthly ATC or AFC, additional capacity becomes available, increase the CBM based on availability up to a maximum of the sum of all CBM requests.<br><br>R5.3. If the sum of all requests can not be met simultaneously, and during the planning process, additional capacity becomes available, increase the CBM based on availability up to a maximum of the sum of all requests.<br><br>R4 High VSL: The Transmission Service Provider did not follow the process described in R4.1, R4.2, and R4.3.<br><br>R4 Severe VSL: The Transmission Service Provider did not follow the process described in R4.1, R4.2, and R4.3, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met.<br><br>R5 High VSL: The Transmission Planner did not follow the process described in R5.1, R5.2, R5.3, and R5.4.<br><br>R5 Severe VSL: The Transmission Planner did not follow the process described in R5.1, R5.2, R5.3, and R5.4, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met.<br><br>Duke Comments:<br><br>1. The current request evaluation process concludes with granting of capacity. If additional capacity becomes available, all parties with an interest in that capacity are permitted to request it and it is made available in queue order under established rules. These rules circumvent the current evaluation process and grant higher priority to unfulfilled CBM requests.<br><br>Response: The SDT has modified the standard such that it allows the Transmission Service provider to choose the manner in which they will handle CBM requests that exceed available capacity. The standard also requires a description of that choice to be included in the CBMID. |

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| | 2. Once an LSE has been denied CBM, the LSE should make other arrangements to meet needs. For example, the LSE could request CBM on a different Posted Path. If other arrangements are made, the LSE no longer needs CBM on the requested path, even if capacity becomes available at a later time.<br><br>Response: The SDT does not disagree, and the LSE has an obligation to both make other arrangements and to modify their request to reduce their need for CBM if those other arrangements are made. If they do not reduce their request, then they may be penalized for so not doing. If they don't make other arrangements and the CBM never becomes available, then they may have problems meeting their generation reliability needs.<br><br>3. If these rules were applied and CBM changed after a rate filings had been submitted by the Transmission Provider (as required in FERC Order 890 paragraphs 257 & 258), the Transmission Provider's filing will be inaccurate.<br><br>Response: Paragraphs 257 and 258 require that Transmission Providers "reflect the set-aside of transfer capability as CBM in the development of the rate for point-to-point transmission service." Paragraph 263 further clarifies "We also require transmission providers to design their transmission charges to ensure that the class of customers not benefiting from the CBM set-aside, i.e., point-to-point customers, do not pay a transmission charge that includes the cost of the CBM set-aside." The rules specified in the standard will not in themselves lead an inaccurate filing, but a rate design that is based in part on a CBM value derived from customer requests may do so, depending on the design. We believe that either the design should be modified to address this concern or the concern should be brought to the FERC by those parties with the concern.<br><br>4. Duke recommends removing these requirements. If additional ATC becomes available, LSEs should submit revised requests for CBM capacity.<br><br>Response: The SDT has modified the standard such that it allows the Transmission Service provider to choose the manner in which they will handle CBM requests that exceed available capacity. The standard also requires a description of that choice to be included in the CBMID.<br><br>- MOD-008-1, Requirements R3 and R4 should allow the Transmission Operator and Transmission Service Provider 14 days instead of 7 days to make the information available after a request, since the responsible individual could be on vacation. The 7 day requirement could be especially burdensome on small entities.<br><br>Response: The SDT reviewed this requirement. Based on your comments and others drafting team made several changes that should address your concerns:<br>#1: R4 on the TSP was removed, it did not make sense for the TSP to serve as aggregator for the Transmission Operators material and would be burdensome on some TSP to have to respond to requests for information that is not theirs.<br>#2: R3 was modified to say make available instead of provide to better reflect the phrasing in other standards and to indicate that shipment of the material is not required, a posting such as a secure FTP site could be sufficient.<br>#3: R3 was modified to require a response to the requestor with the material requested, not a blanket response to all |

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| | parties listed.<br><br>#4: R3 was modified to allow for 30 days instead of 7 days. While the material should be readily available, it is more common to allow 30 days for non critical information transmittal and this resolves the concern at some smaller entities over holidays and vacations.<br><br>#5: Due to the elimination of R4, R3's list of possible requestors was expanded.<br><br>- MOD-028-1, This proposed change, and the corresponding change proposed below for MOD-030-1 (new R3.2) should both be made for consistency. The technical reason for the change is as follows: Each of the two methods needs to use a model large enough in scope to correctly evaluate TTC. The wording regarding equivalent representation of areas also needs to be refined. The base model that is used is already an equivalent model and the standard is allowing for further reduction of the model at greater distances from the region under study. The wording implies that the base model cannot have any reduction for the RC area under study – it should allow for some reduction in the RC area under study and further reduction for the adjacent RC areas and complete elimination for 2nd tier RC areas. To make this proposed change, delete R2.2 and reword R2.1 as follows: Modeling data and topology of its Reliability Coordinator's area of responsibility and immediately adjacent synchronously connected Reliability Coordination areas.<br><br>Response: The standard drafting team has modified the model scope in response to these comments.<br><br>- MOD-028-1, R3.1 Delete the word "intra-peak"<br><br>Response: We have modified the standard to eliminate this typographical error.<br><br>- MOD-028-1, Add new R6.3 to read as follows: Upon the occurrence of a significant contingency such as the loss of 500 MW generation at any location, or loss of any transformer with low side rated greater than 200 kV, or loss of any other transmission facility rated 500 kV or above.<br><br>Response: The standard drafting team has added the following language, "6.3 Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration."<br><br>- MOD-030-1, Delete R3.2, R3.3, R3.4, R3.5 and R3.6 and add new R3.2 to read as follows: Contains modeling data and topology of its Reliability Coordinator's area of responsibility and immediately adjacent synchronously connected Reliability Coordination areas.<br><br>Response: The SDT has modified the standard to incorporate this suggestion, but continued to require that entities model or equivalence adjacent non-synchronous systems.<br><br>- MOD-030-1, Add new R3.3 as follows: Updated as defined below, unless otherwise requested by the Transmission Service Provider: R3.3.1 Updated at least once per day for AFC calculations for intra-day, next day, and days two |

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| | through 30. R3.3.2 Updated at least once per month for AFC calculations for months two through 13. R3.3.3 Updated upon the occurrence of a significant contingency such as the loss of 500MW generation at any location, or loss of any transformer with low side rated greater than 200 kV, or loss of any other transmission facility rated 500 kV or above.<br><br>Response: There are minimum update intervals in the standard. The Transmission Operator and the Transmission service provider are free to agree on a more frequent interval. |
| Response: Please see in-line responses. | |
| Entergy Services Inc. | MOD-001-R2.3 Monthly ATC time period is defined as lasting through month 12. This is not consistent with MOD-030-R3.3 which specifies monthly AFC calculations through month 13. Similar descriptions are included in MOD-028-1 and MOD-029-1. Add in parenthesis "(months 2 through 13)" at the end of this sentence for clarification.<br><br>Response: The Drafting Team has incorporated this change.<br><br>MOD-001-1 R3.1 - replace "may' with "can" in 4th row of this requirement.<br><br>Response: The Drafting Team has incorporated this change.<br><br>MOD-001-1 R3.6 - It is not clear what is expected under Allocation methodology and what needs to be allocated. This requirement should be deleted or Allocation methodology should be more clearly defined.<br><br>Response: The Drafting Team added detail to this requirement to address this concern.<br><br>MOD-001-1 R5 along with R3.2 appears to be "fill in the blank standard" such that the TSP can use any counterflow percentage if they describe how they are accounting for counterflows in R3.2, then R5 is not applicable as it allows them to use their stated method. Therefore, either R5 should be strengthened to make it clear how counterflows and counter-schedules are to be accounted for, or TSP should be allowed to use their method of accounting for counterflows that is included in their ATCID per R3.2.<br><br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. The default values were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed.<br><br>MOD-001-1 R6 - Minimum time of notification before implementing changes in ATCID should be included in this requirement. In addition, notification via electronic mail in parenthesis appears to be the only medium allowed which may not be reliable. Reference to electronic mail should either be removed or other mediums allowed for notification.<br><br>Response: The Drafting Team has elected not to specify a minimum time of notification because, while reliability will be enhanced by advance notice of most changes, the team could envision rare cases where reliability could be impaired by the entity waiting for the notification period to expire before making the change. The parenthetical example was moved from the requirement to the measure and was clarified.<br><br>MOD-001-1 R9.3 - Minimum frequency to update monthly ATC should be once a month rather than once a week. |

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| | Response: The majority of the commenters believed that once a week is an appropriate frequency so the Drafting Team left this unchanged.<br><br>MOD-001-1 R10.12 - This requirement should be deleted as counterflows is not the data to be shared, these are percentage of reservations that are to be used for ATC calculations in a direction opposite to that of reservation that result in increase of the ATC/AFC values.<br><br>Response: The SDT agrees and has removed the requirement.<br><br>MOD-004-1 Effective Date should included "(MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1)" between the words six and standards similar to other standards.<br><br>Response: We have modified the language to make it consistent with the other standards, recognizing that the standards will now be posted for separate ballots.<br><br>MOD-004-1 R1.3 - Words "request the" should be removed as there is no request for schedule, procedure for scheduling of energy is enough.<br><br>Response: The drafting team did not want to imply that the LSE could actually schedule energy, and could only request that the BA schedule that energy on their behalf.<br><br>MOD-004-1 R2 - The Transmission Service Provider needs to make the CBMID available only to the TOs, TSPs, RCs, TPs, and PCs that are in the TSP area or that are adjacent to its network and not to all TOs, TSPs, RCs, TPs, and PCs.<br><br>Response: The standard has been modified to incorporate the suggested change.<br><br>MOD-004-1 R3.1 - CBM is on a Posted Path basis or Flowgate basis whereas GCIR is on an entity basis, therefore either LSE should submit CBM on Posted Path basis or Flowgate basis (LSEs are not expected to know the impact on Posted Paths, or Flowgates of their GCIR, therefore they should preferably just request GCIR and leave calculation of CBM impact to TSP to be determined based on their CBMID under R1.2) which should be included in R3.1, or they can submit GCIR with additional information required in R3.1.1 and TSP shall allocate CBM on Posted Paths or Flowgates based on their CBMID. These requirements need to be made "either Posted Path or Flowgate basis or GCIR" rather than R3.1.1 as additional information required for submitting CBM request.<br><br>Response: The SDT has modified the language slightly, but believes that as written, it is consistent with your intent. The requirements to specify the generation sources of GCIR in R3.1.1.4 allows the LSE to meet the concern you have expressed.<br><br>MOD-004-1 R3.1.2 through R3.1.4 should be deleted or reworded as TSP is not a monitoring entity and they do not have any use for this information. LSE should have this information available for monitoring for compliance. Therefore, these requirements should be reworded accordingly.<br><br>Response: The intent of this language is to allow the TSP 1.) to verify the information if they wish, and 2.) to be able to prove that they set the CBM correctly. The Transmission Service Provider has some responsibility to validate LSE requests, as described in paragraph 1077 of Order 693. The drafting team agrees with you that this information is needed for compliance and serves the responsibilities of both the TSP and the compliance monitor. |

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| | MOD-004-1 R3.2 "every thirty-one days" should be changed to "once a month".<br>Response: The SDT chose the language "every thirty one days" do avoid the ambiguity associated with "once a month (e.g., the 1st of January, the 28th of February, etc…).<br>MOD-004-1 R3.3 - Add "studies conducted in accordance with" between the words "and" and "verifiable".<br>Response: The SDT has modified the standard to incorporate this change.<br>MOD-004-1 R4.1.1 implies that LSE is going to request GCIR on each path which is not realistic for all methods. Since TSPs are required to allocate GCIR on each Posted Path based on their procedure included in CBMID, it should be reflected in this requirement.<br>Response: The SDT has modified the requirement to address this concern by including the following language: "appropriate ATC Path(s)."<br>MOD-004-1 R4.1.2 should be modified to be made similar to R4.1.1 such that entities using Flowgate methodology will allocate GCIR on Flowgates based on R1.2 in their CBMID.<br>Response: The SDT has modified the language slightly, but believe that as written, it is consistent with both your and our intent.<br>A cut off limit of 3% or greater for Distribution Factor is not substantiated and should not be included in the standard. TSPs may be required to include their cut off limit it in their CBMID.<br>Response: The 3% threshold has been removed from the standard.<br>MOD-004-1 R4.2.1 second bullet and R4.2.2 second bullet - since ATC is calculated after deducting the CBM, TRM and Existing Transmission Commitments from TTC, it is unclear which ATC has to be used as limit for allocating CBM.<br>Response: The SDT has modified the standard such that it allows the Transmission Service provider to choose the manner in which they will handle CBM requests that exceed available capacity. The standard also requires a description of that choice to be included in the CBMID.<br>MOD-004-1 R 6.1 - This requirement should be split in two separate sub requirements, the first finishing after the first sentence, and the second sub requirement starts with "If…" and bullets should be made further sub requirements under this new sub requirement as these are applicable only to the situation "If less than the sum of all requests was established as the CBM for any period."<br>Response: The SDT has modified the standard as suggested.<br>System Impact Study is not a viable option; this should be changed to Facility Study.<br>The drafting team thinks that neither term may be the correct term, and has modified R6. to address this concern.<br>MOD-004-1 R7 - "within seven calendar days of their making a request" should also be applicable to sub requirements |

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| | R7.1, since there is no requirement for Transmission Operators to do anything with this data. They can request the data if they need it.<br><br>Response: The SDT has incorporated the suggested change.<br><br>MOD-004-1 R8 - There should be a limit for LSEs to be allowed to schedule only up to the limit of CBM set aside for them as FERC is requiring LSEs to pay for the CBM, if LSEs have not paid for the CBM, they should not be allowed to schedule against the CBM that has been set aside for others. If LSEs do not request enough GCIR and are later allowed to schedule it can adversely impact the reliability of the system.<br><br>Response: FERC has indicated that this is to be treated as a margin, rather than as a transmission service product. Accordingly, the margin will be available for all entities to use, regardless of whether they requested it or not.<br><br>MOD-004-1 R10 - This should be modified to limit the schedule up to the limit of the LSE's CBM reservation or impact of their GCIR on the CBM on the Posted Path or Flowgate. Setting aside CBM is like reserving the Firm Transmission Service, therefore an entity not reserving enough CBM to start with will impact the reliability of the system by overselling the Firm Transmission Service to others.<br><br>Response: R10 has been changed to “The Transmission Service Provider shall approve any Arranged Interchange using CBM that is submitted by an Energy Deficient Entity under an EEA2 if the CBM is available.” The amount of CBM set aside may not be the needed amount but the number one concern is to keep the lights on regardless of the request for CBM.<br><br>MOD-008-1 R1.1 - It may not be possible to identify the impact of each of the uncertainties on each of its respective Posted Paths or Flowgates as included in this requirement. It should be sufficient to include method of coming up with TRM values in terms of percentage or MW taking into account the uncertainties included in this requirement. The language in this requirement should be reworded accordingly.<br><br>Response: The TRM value resulting from the application of R1.1 can be a percentage or MW value developed through the use of the items listed under R1.1. Requirement R1.1 doesn’t require the use of all the quantities listed, nor does is it require a single TRM for all paths.<br><br>MOD-008-1 R2 - The first phrase covers the intent to only use the components of uncertainty from R1.1, the second phrase "and shall not include any of the components of Capacity Benefit Margin (CBM)" is redundant and should be deleted.<br><br>Response: The drafting team agrees this statement is mostly redundant. However for two reasons the team decided to leave it in. The first is FERC order 890 was quite explicit on this point and so to leave it makes the compliance with that point quite explicit. It has also been pointed out in meetings and by commenters scenarios where there could be some overlap between CBM and TRM, so this is a catch all to point out that there is not supposed to be any overlap and the entity doing the TRM calculation is responsible for insuring that.<br><br>MOD-008-1 R4 - Parenthesis around the parenthetical statement "within seven days….." should be removed. |

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| | Response: The SDT has corrected this typographical error.<br><br>MOD-008-1 R5 - There is no justification for the 13 months frequency, it should be changed to once a year or 12 months to be more consistent with business cycles.<br><br>Response: The standards does not preclude a yearly cycle. The intent of the team is that TRM should be calculated on a yearly basis, however not on a 365 day basis. Use of the term yearly or 12 month would cause some auditors to interpret that as 365 days. For example if the entity last reviewed the TRM on Dec 5th, it would have to review it by Dec 5th in the next year. So the next year it is done early on Nov 25th, on the following year it would have to be before that date. By going to 13 month duration the team believes it is encouraging a yearly review, without the entity having to be concerned about being a few days late, or do the task early and thereby “walking” the date for the next review.<br><br>MOD-028-1 R1.1 - Word "may" should be replaced by the word "can" in last line.<br><br>Response: The SDT has changed the words as suggested.<br><br>MOD-028-1 R3 and R4- Insert a word "of" between "all" and "the" in third line.<br><br>Response: The SDT has corrected this typographical error.<br><br>MOD-028-1 R3.1 and 3.2 - Sub-requirements R3.1.1 through R3.1.3 are similar to the sub requirements R3.2.1 through R3.2.3 except using the Load Forecast for corresponding period. The only difference between R3.1 and R3.2 is that one is for the on-peak and the second is for the off-peak with very similar sub-requirements. These requirements should be combined into one requirement to simplify the standard and to be specific. Similar approach should be used for R4 to be merged into one requirement with R3 as the only difference is the period of calculation and to use corresponding Load forecasts.<br><br>Response: The SDT believes providing explicit detail as we have done is clearer.<br><br>MOD-028-1 R5.3 - Sub requirements for using the sources and sinks included as bullets should be converted into numbered sub requirements.<br><br>Response: If sub requirements are used, the entity must satisfy all of the sub requirements. If bullets are used only those bullets that apply to the entity must be satisfied. In this specific requirement, only those bullets that apply to the specified condition will be used.<br><br>MOD-028-1 R6.1 - Since forced outages during the week can impact Hourly and Daily TTCs, frequency of TTC calculations for hourly and Daily ATC calculations should be once a day rather than once a week.<br><br>Response: The standard drafting team has added the following language, “6.3 Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration.”<br><br>MOD-028-1 R7 - It appears there is no consideration of contingencies in this process. Was this the intent of the SDT? If not, the incremental Transfer Capability should be changed to First Contingency Incremental Transfer Capability or |

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| | impact of contingencies should be included in the language of the requirement.<br><br>Response: The drafting team believes reaching (respecting) SOL's incorporates contingencies into the process.<br><br>MOD-028-1 R8 and R6.1 - If Transmission Operator calculates TTC once a week and provide those values to TSP within seven days of calculations, TTC used for Daily and hourly ATC calculations can be as old as 2 weeks, which is unrealistic. The time allowed to transfer TTC values from TO to TSP should be within one day of determination at the maximum, unless otherwise agreed to by the TSP.<br><br>Response: The standard defines the minimum times. Entities are free to negotiate more frequent updates.<br><br>MOD-028-1 R9 and R10 - Is Native Load included in NITS? If so, it should be included in the definition, otherwise, another term for Native Load should be included for ETC equation similar to that included in MOD-029-1 R5.<br><br>Response: All Native Load is modeled in the base case used in determining the FCITC. However, only the portion of Native Load imported on paths that serve as interfaces with other Transmission Service Providers is included in NITS.<br><br>MOD-028-1 R11 and R12 - Postbacks in these requirements refer to as defined in Business Practices, are these NAESB Business Practices or TSP Business Practices? It should be clarified.<br><br>Response: The term Business Practices has been defined.<br><br>MOD-028-1 R12 - Unscheduled Firm reservation need to be offered as non firm, if schedules are not received up to the scheduling deadline. Are these included in the postback definition? If not, these should be included in the equation for non firm ATC calculations.<br><br>Response: This will be included in the Postbacks definition being developed by NAESB. The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks.<br><br>MOD-029-1 R1.10 - "Extra High Voltage (EHV)" should be defined.<br><br>Response: The SDT has eliminated this term from the requirement.<br><br>MOD-029-1 R1.12 - "ACTID" is spelled incorrectly, it should be changed to "ATCID".<br><br>Response: The SDT has corrected this typographical error.<br><br>MOD-029-1 R2.7 - Regional Entity is indicated to have taken action to have the path rated using a different method. There is no requirement in NERC standards for Regional Entity to take action to rate the path, it should be clarified, or reference deleted.<br><br>Response: The SDT has deleted the reference.<br><br>MOD-029-1 R5 and R6 - Definitions of Native Load and NITS include "losses not otherwise included in TRM and CBM |

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| | standards". There are no such provision to separately include losses in TRM or CBM calculations in current versions of MOD-004-1 and MOD-008-1. The difference should be reconciled or reference removed from this requirement.<br><br>Response: The SDT has re-ordered the items in the definition to make the statement more clear.<br><br>MOD-029-1 R6 - There is no term for Native Load in this equation similar to that in R5. Is Native Load never served by a non-firm capacity reservation? If it can be served, the Native Load term should be included in R6 for consistency.<br><br>Response: The SDT believes in this case, non-firm NITS would be used to serve that load.<br><br>MOD-029-1 R7 and R8 - Postbacks use the term business practices with lower case in this standard. Which business practices this term refers to in this standard? Is it referring to the NAESB Business Practice Standards or TSP Business Practices? It should be clarified. If it means the same as in MOD-028-1 R11 and R12, it should be reconciled by capitalizing it and defining it.<br><br>Response: The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks. The SDT has also included a definition of Business Practices.<br><br>MOD-030-1 R2.2 - Change "once per calendar quarter" to "once per calendar year" for the frequency of updating the list of Flowgates.<br><br>Response: The drafting team agrees and changed the update period for internal flowgates to yearly. The drafting team has changed the update period for external flowgates to monthly.<br><br>MOD-030-1 R3.4, R3.5, and R3.6 - The term "topology" should be replaced with "system topology" to reconcile it with the terms used in other NERC standards.<br><br>Response: The SDT has incorporated the suggested change.<br><br>MOD-030-1 R5.1 - Reword this requirement to allow the TSP to apply the outage rules defined in the TSP's ATCID and to include third party outage information "where available". It should read: "Include all expected generation and Transmission outages, additions, and retirements as modeled according to the Transmission Service Provider's outage rules defined in the ATCID during the period calculated for the Transmission Service Provider's area, and where available, for all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed".<br><br>Response: The Transmission Service Provider is required to include "known and expected" information, which we believe should address the concern.<br><br>MOD-030-1 R5.2 - Reword this requirement to make it consistent with R2.1.3.1 by adding a statement on the threshold limit as follows: "For external (third-party) Flowgates with at least a 5% TDF, use any AFC for each specific Flowgate provided by that third party as the AFC for that flowgate."<br><br>Response: The drafting team disagrees, and has clarified the requirement to clarify our intention. The requirement now states "For external Flowgates identified in R2.1.3, use any AFC for each specific Flowgate provided by that |

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| | Transmission Service Provider that calculates AFC for that Flowgate as the AFC "<br><br>MOD-030-1 R6.1.4.2 - Reword to use TSP's rules defined in the ATCID as follows: "Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as defined by the Transmission Service Provider's ATCID."<br><br>Response: The SDT has incorporated this change as suggested.<br><br>MOD-030-1 R6.3 and 6.4, R7.2 and R7.3 - Threshold of 3% is specified in the requirement with a foot note that TSPs may use a lower than 3% threshold, if desired. The threshold appears to be at the discretion of the TSP, therefore, it should be stated clearly as such. TSPs may be required to disclose it and include it in their ATCID for transparency purposes.<br><br>Response: The SDT agrees, and has incorporated the suggestion into the standard.<br><br>MOD-030-1 R8 - The capitalized term Business Practices used in Postback seems to refer to some defined Business Practices like NAESB or TSP business practices. Either the term should be defined under definitions, or it should be clarified in the requirement. Also, this term is not capitalized in R9, does it mean it is different business practices. The difference should be reconciled.<br><br>Response: The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks.<br><br>MOD-030-1 R10 - To make this standard consistent with MOD-028-1 and MOD-029-1, there is no need to include an algorithm in this standard. In addition parenthetical "(and TFC to TTC)" should be deleted. The requirement can read "Transmission Service Provider shall convert or provide a tool to convert Flowgate AFCs to TTCs for Posted Paths by using appropriate distribution factors." and delete the remaining language from this requirement. In case this proposed change is not implemented by the SDT, Entergy proposes that the terms used in this requirement like OTDF Flowgate and PTDF Flowgate should either be defined or clarified.<br><br>Response: Order 890, paragraph 211, requires that a clear methodology for converting AFCs into ATCs be provided. This requirement attempts to meet that directive. The drafting team has provided definitions for OTDF, PTDF, and Flowgate. |
| Response: Please see in-line responses. | |
| EPSA | |
| ERCOT | |
| Fall River Rural Electric Cooperative, Inc. | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| FirstEnergy Corp. | 1. MOD-001-1:<br><br>- Applicability - Should include the Reliability Coordinator (RC). Per the NERC functional model, the RC is responsible |

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| | for the "coordination of ATC with Transmission Service Providers".<br><br>Response: While the functional model does charge the RC with the "coordination of ATC with Transmission Service Providers," the drafting team did not find any applicable requirements for the RC with regard to the determination of ATC, TTC, AFC, or TFC.<br><br>- R1 - The Transmission Operator (TOP) should not be responsible for choosing an ATC methodology; any methodology should be coordinated with the TOP, but the ultimate responsibility should fall onto the TSP. Also, it should be made clear that the use of the three methodologies must be in accordance with the "MOD" standards. Therefore, we propose a rewording of R1 as follows: "The Transmission Service Provider, in coordination with the Reliability Coordinator and Transmission Operator, shall choose an ATC methodology [footnote 1] (Area Interchange methodology, Rated System Path methodology, or Flowgate methodology in accordance with MOD-028, MOD-029, and MOD-030, respectively) for each Posted Path per time period for use in determining Transfer Capabilities of those Facilities within its Planning Coordinator's planning area".<br><br>Response: The Transmission Operator is responsible for developing the SOLs that are a part of determining TTCs. As the development of TTC is not specifically assigned to any single entity in the Functional Model, the drafting team believed this to be the appropriate assignment. We suggest that any concerns with the Functional Model be brought to the team currently working to update the model.<br><br>- R8 should not include the Transmission Operator. The TOP is not responsible for calculating the ATC, TTC, or AFC.<br><br>Response: The Transmission Operator is responsible for developing the SOLs that are a part of determining TTCs. As the development of TTC is not specifically assigned to any single entity in the Functional Model, the drafting team believed this to be the appropriate assignment. We suggest that any concerns with the Functional Model be brought to the team currently working to update the model.<br><br>2. MOD-004-1:<br><br>- R3 - This requirement should either be eliminated or specified under R1, as applicable to TSPs. Where R1 requires the TSP to have a procedure for LSEs to request CBM, R3 prescribes part of that procedure. If R1 is intended to give TSPs full liberty to develop its CBM procedure, then R3 is an unnecessary requirement. If instead R3 is an element of the procedure that must be common to all, then it should be added as a requirement for TSPs to include in their procedures.<br><br>Response: R3 requires that LSEs provide certain information to the TSP when requesting CBM. It is not the obligation of the TSP to require this information; to ensure reliability, it is the obligation of the LSE who wants CBM to provide this information to the TSP.<br><br>- R8 - This requirement should be included in a NAESB business standard. Any aspects of R8 as applicable to TSPs should remain.<br><br>Response: Since the scheduling of CBM is a reliability based issue, the SDT believes it is appropriate to include some |

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| | requirements within the standard.<br><br>- Effective Date: For consistency, the Effective Date section should be replaced to match what is in the other proposed standards under the Proposed Effective Date which references the other standards and is more complete that what is shown in MOD-004.<br><br>Response: The effective date language has been modified and made consistent with the other standards, recognizing that the standards will now be posted for separate ballots.<br><br>3. MOD-008-1:<br><br>- Applicability - Since TRM is a network-wide margin critical to calculating ATC, the TRM standard should also be applicable to the Reliability Coordinator (RC). Per the NERC functional model, the RC is responsible for the "coordination of ATC with Transmission Service Providers". Lastly, the RC must be included as an applicable entity as directed by FERC Order 693, Par. 1126.<br><br>Response: "Applicability" is intended to indicate the entities that have been assigned requirements under the standard. The drafting team was unable to find any requirements that applied to the RC; therefore, the RC is not included in the applicability section. We do require in R3 that the RC be informed of the TRMID and supporting calculations used to determine TRM.<br><br>- R1 - Since the Transmission Service Provider (TSP) is ultimately responsible for calculating and assuring proper ATC for its footprint, and since, per MOD-004-1 R1, the TSP is responsible for maintaining a CBMID, then it should follow that the TSP, and not the Transmission Operator (TOP), should be responsible for maintaining a TRMID. Plus, in R4 of MOD-008-1, the TSP has to make the TRMID available to other TSPs when requested. Wouldn't the process be smoother and more reliable if the TSP didn't first have to ask the TOP for the TRMID if the TSP already had and maintained its own TRMID? Therefore R1 should be reworded as follows: "Each Transmission Service Provider, in coordination with the Transmission Operator and Reliability Coordinator, shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information:"<br><br>Then, if R1 is changed as suggested, the following changes to other requirements to MOD-008-1 must be considered:<br><br>- R2 & R3 - Replace "Transmission Operator" with "Transmission Service Provider"<br><br>- R3.1 - Reword as follows: "The Transmission Operators with Facilities governed by the Transmission Service Provider".<br><br>- R4 - Remove "used by its Transmission Operator(s)"<br><br>- R5 - "Each Transmission Service Provider shall calculate, at least once every 13 months (in accordance with the definitions in its TRMID), a TRM value for the following time periods (on each Posted Path or Flowgate) and shall provide these TRM values to its Transmission Operator(s) and Transmission Planner(s) within seven calendar days of the calculation:<br><br>Response: The SDT interprets the functional model to state that the Transmission Operator is responsible for the |

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| | situations that lead to needing TRM (e.g., emergency operations, developing contingency plans, etc...). As such, the SDT believes it is the responsibility of the TOP to determine TRM. However, the SDT also believes that the TSP is responsible for coordination with other entities; hence the exchange of information between the Transmission Operator and Transmission Service Provider.<br><br>4. MOD-030-1:<br><br>- Applicability - Since Flowgates are points within the Transmission system through which Interchange Distribution Calculations are performed by the Reliability Coordinator, this standard should also be applicable to the Reliability Coordinator (RC). Also, per the NERC functional model, the RC is responsible for the "coordination of ATC with Transmission Service Providers".<br><br>Response: While the functional model does charge the RC with the "coordination of ATC with Transmission Service Providers," the drafting team did not find any applicable requirements for the RC with regard to the determination of ATC, TTC, AFC, or TFC. Note that Flowgates used for congestion management are different from those used by ATC.<br><br>- R2 - Although the Transmission Operator assists with gathering this information, this requirement should ultimately be the responsibility of the Transmission Service Provider (TSP), since the TSP prepares and maintains the Available Transfer Capability Implementation Document (ATCID). Also, the Reliability Coordinator should assist in gathering this data since this entity is closely monitoring Flowgate capacities in its area. Therefore, we suggest rewording R2 as follows: "The Transmission Service Provider, in coordination with the Transmission Operator and Reliability Coordinator, shall perform the following:"<br><br>Response: Requirements in general must be assigned to a single functional entity. While that entity may seek assistance from other entities, language such as “in coordination with” implies a sharing of responsibility which does not in fact exist; therefore, we have chosen not to present it in this fashion. The Transmission Operator is responsible for developing the SOLs that are a part of determining TTCs. As the development of TTC is not specifically assigned to any single entity in the Functional Model, the drafting team believed this to be the appropriate assignment.<br><br>- R3 - Incorrectly states that the Transmission Operator (TOP) determines the AFC. R3 should be reworded as follows: "The Transmission Operator, in coordination with the Reliability Coordinator, shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria:”<br>Response: The SDT doesn’t recognize the role of the Reliability Coordinator for developing a Transmission model. R3 has been modified to remove the Transmission Operator from determining AFC. |
| Response: Please see in-line responses. | |
| Flathead | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |

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| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| FRCC | MOD 001: R9: This should be revised to indicate that updates are required only when data has changed. There are many entities whose ATC data may not change on a regular basis and requiring them to repost identical numbers on an hourly basis and maintain a log does not enhance reliability. Proposed wording "Each Transmission Service Provider shall update ATC at a minimum on the following frequency when the value has changed:"<br><br>Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br><br>MOD-004-1: CBM: There does not seem to be a way to not have a CBMID even though the TSP policy is not to reserve CBM on any of its interfaces. Could the applicability be modified to exclude entities that do not use CBM?<br><br>Response: We have modified the standard to address your concern and make it compliant with Order 890-A.<br><br>MOD-008-1: TRM: The sub-requirements in R1.4 and R5 describe the ATC Operating, ATC Scheduling, and ATC Planning horizons as specified by FERC in Order 890 and should be identified by name to be consistent with the other MOD standards.<br><br>Response: The horizons defined by FERC do not necessarily agree with those used in the industry and in other standards. As such, the SDT felt it would be more appropriate to specify the explicit times without the names.<br><br>MOD-028-1: Area Interchange Methodology: R3 appears to require calculating TTCs for Posted Paths for intra-day and next day, on-peak and off-peak, R4 requires calculating TTCs for time periods beyond next day, and then R6 specifies frequencies that don't correspond. For example, R4.1.2 requires use of peak load forecast for the day being calculated, but R6.1 says calculate TTC for daily only once per week – which day's peak load forecast gets used?<br>Response: R6 describes how often the Transmission Operator should perform the calculation. Depending on the timeframe of the TTC being calculated, R3 and R4 describe the appropriate data for the period that is being calculated. |
| Response: Please see in-line responses. | |
| Georgia Transmission Corporation | In MOD-008-1, R5, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. An error in calculating TRM does not change the resulting TTC or TFC; therefore an error in calculating TRM cannot be a Medium or Severe Violation Risk Factor.<br><br>Response: As a result of the discussions subsequent to your comment, the drafting team split the old requirement R5 to two requirements (R4 and R5, the old R4 being deleted). This split allowed the team to review the criticality of recalculation of TRM and transmission of updated TRM values. The team determined that of the requirements, these |

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| | two are the most critical with regard to the capability of the electric system. Therefore the standard maintains a Medium VRF for both.<br><br>In MOD-028-1, R2, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that using a model that does not meet the criteria specified in R2 can result in an TTC that is greater than the SOL or IROL Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system<br><br>In MOD-028-1, R3, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that using a data different than that specified in R3 can result in a TTC that is greater than the SOL or IROL. The SDT also believe that not adhering to the time frames specified can lead to an inaccurate ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system<br><br>MOD-028-1, R5 uses to the term "interface point" with the adjacent Transmission Service Provider; "interface point" is not defined. To meet MOD-028-1, R5 and MOD-030-1, R4, a Transmission Operator must define and simulate an artificial source or sink at the interface. The requirements should replace each occurrence of the phrase "use the interface point" with the phrase "use the adjacent Transmission Service Provider's area".<br><br>We have modified the standard to address this concern. A representative example of the new language is as follows: use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.<br><br>MOD-028-1, R8 is missing a Violation Risk Factor and a Time Horizon. They should be Violation Risk Factor: Lower and Time Horizon: Operations Planning.<br><br>Response: The drafting team has added this section, chose to set the VRF and Time Horizon to Medium and Operations Planning.<br><br>In MOD-028-1, R9, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: drafting team disagrees. A violation of R9 can create a situation where the service sold is in excess of the |

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| | TTC less the true ETC, resulting in over-scheduling of the path. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-028-1, R11, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: drafting team disagrees. A violation of R11 can create a situation where the service sold is in excess of the TTC less the true ETC, resulting in over-scheduling of the path. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-029-1, R1, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that using a model that does not meet the criteria specified in R1 can result in an ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-029-1, R2, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that not complying with R2 can result in a TTC that is greater than the SOL or IROL. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-029-1, R5, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. A violation of R5 can create a situation where the service sold is in excess of the TTC less the true ETC, resulting in over-scheduling of the path. Accordingly, the SDT believes a violation can have |

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| | a negative effect on the reliability of the system.<br><br>In MOD-029-1, R7, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. A violation of R7 can create a situation where the service sold is in excess of the TTC less the true ETC and other components, resulting in over-scheduling of the path. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-030-1, R2, the Violation Risk Factor is listed as Lower; it should be listed as Medium. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. MOD-030-1, R2 requires that the TFC be less than the SOL; therefore MOD-030-1, R2 should have a Medium Violation Risk Factor.<br><br>Response: The SDT has incorporated the suggested change.<br><br>In MOD-030-1, R3, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that using a model that does not meet the criteria specified in R3 can result in an ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>MOD-030-1,R4 uses the term "interface point" with the adjacent Transmission Service Provider; "interface point" is not defined. To meet MOD-028-1, R5 and MOD-030-1, R4, a Transmission Operator must define and simulate an artificial source or sink at the interface. The requirements should replace each occurrence of the phrase "use the interface point" with the phrase "use the adjacent Transmission Service Provider's area".<br><br>Response: The SDT has modified the standard to address this concern. A representative example of the new language is as follows: use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.<br><br>In MOD-030-1, R5, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be |

<table>
<tr><th>Commenter</th><th>3. Comments on Requirements</th></tr>
<tr><td></td><td>Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that not incorporating the information described in R5 can result in an ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-030-1, R6, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that not implementing R6 correctly can result in an ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-030-1, R9, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that not implementing R9 correctly can result in an ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Hydro One Networks</td><td></td></tr>
<tr><td>Hydro-Québec TransÉnergie (HQT)</td><td>MOD-001<br><br>1. R1: The reference to the Planning Coordinator’s planning area in R1 is not appropriate; the reference should be to the Transmission Operator’s operating area.<br><br>Response: The SDT has modified the standard to incorporate this change.<br><br>2. R3.3: Since this standard deals with short-term Transmission Service, the reference to Planning Coordinator should be removed from R3.3, R6.1 and R6.4<br><br>Response: Because ATC can impact months 12 and 13, the SDT believes the Planning Coordinator should be made aware of any such changes based on the descriptions in the functional model.<br><br>3. R3.3: This should be reworded to be clear that the TOP is providing input (TTC or TFC) to the TSP to perform</td></tr>
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| | ATC calc. Also suggest removing reference to a 'tariff' since non-jurisdictional entities may not have a tariff. Suggest the following language: The identity of the Transmission Operators that provide data on each Posted Path for use by the Transmission Service Provider in calculating ATC.<br><br>Response: The SDT has modified the standard to address your concerns.<br><br>Acronyms TOP, TFC, and TSP need to be defined in the Background Information on p. 3. The abbreviation "calc." should be spelled out.<br><br>Response: The Background Information will not become part of the Standards, and as such is not being revised. The Drafting Team believes TOP, TFC and TSP have been adequately defined in the Standards or the NERC Glossary of Terms. The Drafting Team could not find the abbreviation "calc." referred to.<br><br>4. R4 and R5 should reference both the terms counter-schedules and counterflow throughout the requirements<br><br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>5. R9 (or at a minimum the Measure for R9) must be modified to be clear that if TSP can demonstrate that no inputs to the ATC calculation have changed that an update of a 'timestamp' on an ATC value is not required. Suggested options for the language in R9: "Each TSP shall update ATC at a minimum on the following frequency, except that if all inputs to ATC are unchanged no update is required:" OR "Each TSP shall update ATC at a minimum on the frequencies listed below. However, if all inputs to ATC are unchanged no update is required."<br><br>Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br><br>MOD-029<br><br>1. R1.10 refers to EHV without it being a defined term and different regions could define EHV to be different voltage levels; suggest one of the following actions be taken: (a) include the desired kV level of the BPS system in the standard, (b) remove the reference to EHV entirely, (c) add a NERC glossary term. EHV should be defined in the Background Information on p.3 and be understood to be applicable to and restricted to the BPS irrespective of that voltage level. That definition must also include the BPS voltage level it refers to.<br><br>Response: The SDT has eliminated the reference to EHV.<br><br>2. R2 language could be interpreted that all N-2 contingencies must be considered in a TTC study. If the intent that the TTC study should consider all currently required planning criteria, a general reference should be made to the planning standards rather than try to summarize and reiterate those requirements here.<br><br>Response: The SDT agrees and have modified R2.1, R2.1.1 & R2.1.2 to address your concerns by removing reference |

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| | to N-0, N-1 & N-2.<br><br>3. R2.1.5 contains a very specific consideration for EHV contingencies to be considered in the TTC. Is there a reliability need for ALL regions to consider EHVs in this manner? If not, we suggest removing this requirement from the NERC standard, where it can be added in a more detailed regional standard if required by a particular region. EHV should be defined in the Background Information on p. 3; the definition must include the BPS voltage level it refers to.<br><br>Response: The SDT has eliminated this requirement in response to your concern. |
| Response: Please see in-line responses. | |
| IESO | MOD-001:<br><br>- R1: We question the appropriateness of retaining the calculation of TTC within the MOD series standards rather than inclusion with the FAC series standards to assure consistency with the calculation of Total Transfer Capability (TC). While FERC did not explicitly direct the ERO to develop the TTC in FAC-012 as the NOPR had proposed, it nonetheless directed that the short and long-term calculations be consistent with TC to the extent possible (Order 693 @ P1039). To achieve such consistency, and to avoid virtually identical requirements in 2 standards, it is our view that TTC calculation should be part of the FAC-012 standard.<br><br>Response: The SDT believes that that the inter-related nature of TTC and ATC requires that these two concepts be contained within one standard. To eliminate concerns with having virtually identical requirements in two standards, the SDT has proposed in the implementation plan the elimination of FAC-12.<br><br>Further, we are unable to see the relevance of a Planning Coordinator's “planning area” in the TOP's determination of TTC and TSP's determination of ATC since the areas under the purview of a TOP, TSP and PC may differ among them. If an appropriate area needs to be included in the requirements then we would suggest the a Transmission Operator's area be specified for a TOP's determination of TTC, and a Transmission Service Provider's area be specified for a TSP's determination of ATC.<br><br>Response: The SDT has modified the requirement to incorporate the suggested change.<br><br>- R3: We do not agree that R3.1 to R3.6 are sub-requirements. They are attributes that need to be included (at a minimum) in the ATCID. The violation severity level of R3 would then depend on the number of these attributes not included in the ATCID.<br><br>Response: Each of these items is required, and therefore the SDT believes they should be enumerated as sub-requirements.<br><br>Additionally, the IRC is concerned with the drafting teams approach to explicitly defining the method (ATCID) to be used to consolidate the required information. While we may agree the ATCID may be conducive for audit purposes, requirements should only specify “what” is required and leave the “how” it is to be compiled to the responsible entity.<br><br>Response: The development of the ATCID (and the CBMID and TRMID) is intended to create a single set of documentation that can be shared with neighboring entities for reliability coordination and understanding. It is also intended to facilitate coordination between the NERC and NAESB standards. The SDT does not believe it to be unnecessarily prescriptive, and if entities have other documents that contain this information, believes it would be acceptable to simply combine those documents under a single cover sheet. |

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| | - R6: We do not see the need to include Planning Coordinator in the list of entities to inform before a TSP implements a revised or new ATCID.<br><br>Response: Because ATC can impact months 12 and 13, the SDT believes the Planning Coordinator should be made aware of any such changes based on the descriptions in the Functional Model.<br><br>- R8: We suggest splitting this into two requirements - one for the TOP on TTC and one for TSP on ATC. Having a requirement to hold two entities to each comply with a specific part of it creates difficulties for developing violation risk factors, measures and violation severity level, and for compliance audit.<br><br>Response: The SDT does not believe this structure creates any difficulties. Both entities are expected to comply, and each entity will be held responsible only for their own violations.<br><br>- R9: There are markets which do not require reservations and hence it does not make sense that the ATC values should be reviewed or posted per this requirement because by the very nature of such market operations, the ATC/TTC values are pretty much static and only change when system conditions change and have a direct impact on the values. The requirement must be modified with a qualifier statement so that these values need to be reviewed and posted for the following conditions and the fact that these can be applied to areas with and without reservations. The following qualifier could be added: “The ATC shall be updated by the Transmission Service Provider if (a)The ATC/TTC values have changed since the last update and the TSP can provide documentation as to why these numbers had not changed until then and (b) The other TSP has changed the ATC/TTC values.” The main intention of the FERC Order 693 regarding the MOD standards was to ensure consistency, transparency, and communication and we believe that even though there is a mention of "frequency of posting" - section 1057, Order 693 - "...include a requirement that ATC be updated by all transmission providers on a consistent time interval..." the requirement, as is written now, is very prescriptive and the frequency of posting, especially the hourly postings/certifications is not required and is very cumbersome and extremely burdensome. The correct ATC/TTC values should always be posted on the appropriate website as this is a reliability consideration – this is what the standard requirement should capture - but the frequency of posting should be a NAESB requirement and not a “reliability standard”.<br><br>Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. However, these standards do not refer to the posting of the data, only the calculation of it. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br><br>R10: The requirement as written is difficult to understand. Suggest to delete the phrase "to each requester" to add clarify.<br><br>Response: The Drafting Team has modified the language (including the deletion of the phrase “to each requester”) to add clarity; however, due to the nature of the requirement, it is a somewhat complex statement. The list of data that may be requested has been converted to a bulleted list to reflect the concept that not all the data has to be provided but only what has been requested out of that list.<br><br>Further, similar to our comments on R3, R10.1 to R10.15 are the data to be provided. They are not sub-requirements.<br><br>Response: Each of these items is required, and therefore the SDT believes they should be enumerated as sub- |

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| | requirements.<br><br>MOD-004<br>- R1: R1.1 to R1.3 are elements to be included in the CBMID, they are not sub-requirements.<br>Response: Each of these items is required, and therefore the SDT believes they should be enumerated as sub-requirements.<br><br>- R2: The TSP should post the CBMID on the OASIS rather than making it available to the selected entities only.<br>Response: The SDT does not disagree. However, for reliability purposes, only entities listed need to be aware of the changes. NAESB will deal with posting requirements. Note that posting the information on OASIS and giving the entities listed access to it would meet the requirement.<br>- R5: We are unable to see the role of a Transmission Planner in setting the value of CBM. TP is a recipient of the CBM value for considering in its transmission planning process, not the setter. The TSP should be performing the tasks listed in R5 upon receiving requests from the LSEs.<br>Response: Based on the Functional Model, the SDT believes that once the determination of CBM extends beyond the current year, the Transmission Planner must be involved in setting the value.<br>- R7: Accordingly, the TP should not be responsible for providing supporting data used for allocating CBM.<br>Response: Based on the Functional Model, the SDT believes that once the determination of CBM extends beyond the current year, the Transmission Planner must be involved in setting the value.<br><br>MOD-008<br>- R1: R1.1 to R1.4 are elements to be included in the TRMID, they are not sub-requirements. R1.5 is a legitimate sub-requirement; it doesn't need to be changed.<br>Response: The team discussed the difference between bullets and sub-requirements quite extensively. The team decided that bullet lists are appropriate for items that may or may not be included in something, a progression of steps, sequence of events or a listing of similar items. In the case of the TRM calculations, the items in 1.1 may or may not be included based on the entity's TRM method and are similar, therefore they are listed together. Sub-requirements 1.2,1.3 and 1.4 are not optional but must be performed. In addition items 1.2,1.3 and 1.4 do not have much in common in terms of structure and are rather too long to lend themselves to bulleted lists.<br>However the team did clarify in the VSL listing that violation of more then one sub-requirement is not multiple violation, but a single violation with varying levels of severity depending on the number of sub-requirements not met. While the drafting team did not make the sub-requirements bullets, this change may satisfy your concern. |

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| | - R4: The TSP should post the TRMID and related information on the OASIS rather than making it available to the requesting TSPs only.<br><br>Response: The SDT does not disagree. However, for reliability purposes, only entities listed need to be aware of the changes. NAESB will deal with posting requirements. Note that posting the information on OASIS and giving the entities listed access to it would meet the requirement.<br><br>MOD-030<br><br>- R2.3 does not identify that TFC can be limited by an IROL but it should.<br><br>Response: Based on current standards, all IROLs are inherently SOLs, so a requirement to honor SOLs includes IROLs.<br><br>If selling transmission service really requires development of a reliability standard, R2.4 should be modified to require updating the TFC any time the underlying determinants, such as facility ratings, change.<br><br>Response: The SDT added requirement R2.5.1 in MOD-030 to include that rating updates from the Transmission Owner require the TFC to reflect the change.<br><br>- R3.4 requires that a TOP include all modeling and topology for Facilities in the Reliability Coordinator Area. For a small TOP within a large RC, this may be overkill.<br><br>Response: The SDT feels that requiring the model to contain the facilities in the RC area will be required for consistent, reliable calculation of AFC. The standard drafting team feels that it will not be burdensome to supply such data even for a small TOP within a large RC. The team has added a statement saying, "Equivalent representation of radial lines and facilities161kV or below is allowed," which should help with the modeling.<br><br>R3.5 arbitrarily requires a model to include 3 contiguous busses from the tie-line into synchronously connected systems and R3.6 requires at least an equivalent representation further in than that. These are not appropriate or acceptable methods for determining modeling detail level. There exist commercially available modeling packages that can be used to determine the impacts of the external system and how much detail should be kept. There should be a requirement(s) that establishes thresholds such as percent impact of flows on the TOP system for removal of facilities from the external footprint. If the impact exceeds that threshold, then the external facility should be modeled in detail.<br><br>Response: The SDT has changed this requirement to be consistent with MOD-028, which requires the modeling or equivalencing of adjacent Reliability Coordinator areas. This level of modeling detail provides some of the effects of the neighboring without burdening the Transmission Operator. However, additional modeling detail can be used.<br><br>This standard should not include any requirements on the Transmission Operator. R2 should be a requirement on the Transmission Service Provider. Ultimately, they will have to work with the TOP to identify the flowgates and it is in the best interest of the TOP to help the TSP but the requirement should not apply to the TOP. This drafting team should work with the appropriate drafting team developing TOP requirements to ensure that there is a requirement for the TOP to communicate limits to the TP.<br><br>Response: The SDT believes that the functional model indicates this requirement is the responsibility of the |

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| | Transmission Operator.<br><br>R3 should not apply to the TOP. It should apply to the TSP. The TSP should use system limit inputs such as SOL and IROL given by the TOP to determine TFC. Ultimately, R3 should be a simple requirement for the TSP to use the system limits determine by the TOP per FAC standard to define the TFC. No sub-requirements are then required.<br><br>Response: The SDT believes that the functional model indicates this requirement is the responsibility of the Transmission Operator.<br><br>MOD-028<br><br>- R2.2 is not clear - modeling "beyond Reliability Coordination Areas" may not be feasible in many cases, especially when entire second or third tier RCs have to be modeled - adjacent RC area modeling is a must but modeling of beyond adjacent RC areas should be at the discretion of the Transmission Operator. Also, R2.1 through R2.3 are model parameters and not requirements per se.<br><br>Response: By allowing for "equivalent representation" of these areas, the entire second or third tier RCs area is not required to be modeled; we are allowing for significant flexibility in this requirement.<br><br>MOD-029<br><br>- R2.1.5 is worded inconsistently with the rest of the bullet points. It should read as: "System disturbances for stability studies by a three-phase-to-ground fault on all modeled "Extra High Voltage (EHV)" buses adjacent to the major interconnection point of the modeled Posted Path should not render the system unstable".<br>Response: The SDT has deleted this requirement in response to your comment.. |
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| ISO/RTO Council (IRC) | For MOD-001:<br><br>- R1 - We question the appropriateness of retaining the calculation of TTC within the MOD series standards rather than inclusion with the FAC series standards to assure consistence with the calculation of Total Transfer Capability (TC). While FERC did not explicitly direct the ERO to develop the TTC in FAC-012 as the NOPR had proposed, it nonetheless directed that the short and long-term calculations be consistent with TC to the extent possible (Order 693 @ P1039). To achieve such consistency, and to avoid virtually identical requirements in 2 standards, it is the IRC's view TTC calculation should be part of the FAC-012 standard.<br><br>Response: The SDT believes that that the inter-related nature of TTC and ATC requires that these two concepts be contained within one standard. To eliminate concerns with having virtually identical requirements in two standards, the SDT has proposed in the implementation plan the elimination of FAC-12.<br><br>Further, we are unable to see the relevance of a Planning Coordinator's "planning area" in the TOP's determination of TTC and TSP's determination of ATC since the areas under the purview of a TOP, TSP and PC may differ among them. If an appropriate area needs to be included in the requirements then we would suggest the a Transmission Operator's |

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| | area be specified for a TOP's determination of TTC, and a Transmission Service Provider's area be specified for a TSP's determination of ATC.<br><br>Response: The SDT has modified the requirement to incorporate the suggested change.<br><br>- R3: We do not agree that R3.1 to R3.6 are sub-requirements. They are attributes that need to be included (at a minimum) in the ATCID. The violation severity level of R3 would then depend on the number of these attributes not included in the ATCID.<br><br>Response: Each of these items is required, and therefore the SDT believes they should be enumerated as sub-requirements.<br><br>Additionally, the IRC is concerned with the drafting teams approach to explicitly defining the method (ATCID) to be used to consolidate the required information. While we may agree the ATCID may be conducive for audit purposes, requirements should only specify “what” is required and leave the “how” it is to be compiled to the responsible entity.<br><br>Response: The development of the ATCID (and the CBMID and TRMID) is intended to create a single set of documentation that can be shared with neighboring entities for reliability coordination and understanding. It is also intended to facilitate coordination between the NERC and NAESB standards. The SDT does not believe it to be unnecessarily prescriptive, and if entities have other documents that contain this information, believes it would be acceptable to simply combine those documents under a single cover sheet.<br><br>- R6: We do not see the need to include Planning Coordinator in the list of entities to inform before a TSP implements a revised or new ATCID.<br><br>Response: Because ATC can impact months 12 and 13, the SDT believes the Planning Coordinator should be made aware of any such changes based on the descriptions in the Functional Model.<br><br>- R8: We suggest splitting this into two requirements - one for the TOP on TTC and one for TSP on ATC. Having a requirement to hold two entities to each comply with a specific part of it creates difficulties for developing violation risk factors, measures and violation severity level, and for compliance audit.<br><br>Response: The SDT does not believe this structure creates any difficulties. Both entities are expected to comply, and each entity will be held responsible only for their own violations.<br><br>- R9: There are markets which do not require reservations and hence it does not make sense that the ATC values should be reviewed or posted per this requirement because by the very nature of such market operations, the ATC/TTC values are pretty much static and only change when system conditions change and have a direct impact on the values. The requirement must be modified with a qualifier statement so that these values need to be reviewed and posted for the following conditions and the fact that these can be applied to areas with and without reservations. The |

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| | following qualifier could be added: "The ATC shall be updated by the Transmission Service Provider if (a)The ATC/TTC values have changed since the last update and the TSP can provide documentation as to why these numbers had not changed until then and (b) The other TSP has changed the ATC/TTC values." The main intention of the FERC Order 693 regarding the MOD standards was to ensure consistency, transparency, and communication and we believe that even though there is a mention of "frequency of posting" - section 1057, Order 693 - "...include a requirement that ATC be updated by all transmission providers on a consistent time interval..." the requirement, as is written now, is very prescriptive and the frequency of posting, especially the hourly postings/certifications is not required and is very cumbersome and extremely burdensome. The correct ATC/TTC values should always be posted on the appropriate website as this is a reliability consideration – this is what the standard requirement should capture - but the frequency of posting should be a NAESB requirement and not a "reliability standard".<br><br>Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. However, these standards do not refer to the posting of the data, only the calculation of it. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br><br>- R10: The requirement as written is difficult to understand. Suggest to delete the phrase "to each requester" to add clarify.<br><br>Response: The Drafting Team has modified the language (including the deletion of the phrase "to each requester") to add clarity; however, due to the nature of the requirement, it is a somewhat complex statement. The list of data that may be requested has been converted to a bulleted list to reflect the concept that not all the data has to be provided but only what has been requested out of that list.<br><br>Further, similar to our comments on R3, R10.1 to R10.15 are the data to be provided. They are not sub-requirements.<br><br>Response: Each of these items is required, and therefore the SDT believes they should be enumerated as sub-requirements.<br><br>MOD-004<br><br>- R1: R1.1 to R1.3 are elements to be included in the CBMID, they are not sub-requirements.<br><br>Response: Each of these items is required, and therefore the SDT believes they should be enumerated as sub-requirements.<br><br>- R5: We are unable to see the role of a Transmission Planner in setting the value of CBM. TP is a recipient of the CMB value for considering in its transmission planning process, not the setter. The TSP should be performing the tasks listed in R5 upon receiving requests from the LSEs.<br><br>Response: Based on the Functional Model, the SDT believes that once the determination of CBM extends beyond the |

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| | current year, the Transmission Planner must be involved in setting the value.<br><br>- R7: Accordingly, TP should not be responsible for providing supporting data used for allocating CBM.<br><br>Response: Based on the Functional Model, the SDT believes that once the determination of CBM extends beyond the current year, the Transmission Planner must be involved in setting the value.<br><br>MOD-008<br><br>- R1: R1.1 to R1.4 are elements to be included in the TRMID, they are not sub-requirements. R1.5 is a legitimate sub-requirement; it doesn't need to be changed.<br><br>MOD-29<br><br>- R1.6. We suggest this bullet be deleted. This is already addressed in R2 wherein the modeling process is dictated. In the RSP methodology, “peak load forecasts” are not used to stress the system; rather, load and generation are simulated to stress the system to its greatest capacity. There are cases when the highest forecasted load may not stress the system to its greatest utilization – which is the goal of the R2 under the RSP.<br><br>Response: The SDT has removed the requirement for “peak” load forecasts, but believe load forecasts in general sill provide value.<br><br>- R2.3 We suggest correcting “…as determined by R1.2.1…” to read “…as determined by R2.1.”<br><br>Response: The SDT has corrected this typographical error.<br><br>- R5. The language describing Native Load should be changed from “reserved” to “encumbered.” Encumbered is the word most frequently used in conjunction with OASIS to describe this condition. The same change should apply to GF sub F.<br><br>Response: The SDT has elected to use the term “set aside” in response to this comment.<br><br>The language describing Grandfathered capacity includes the defined terms “Firm” and "Transmission Service." Use of these words as defined terms is inconsistent throughout the proposed standards. They should either be changed here to a lower case or all applicable areas in each proposed standard should be changed to the defined term.<br><br>Response: The SDT aggress and has made the changes for consistency.<br><br>MOD-030<br><br>- R2.3 does not identify that TFC can be limited by an IROL but it should.<br><br>Response: Based on current standards, all IROLs are inherently SOLs, so a requirement to honor SOLs includes IROLs.<br><br>If selling transmission service really requires development of a reliability standard, R2.4 should be modified to require updating the TFC any time the underlying determinants, such as facility ratings, change.<br><br>Response: The SDT added requirement R2.5.1 in MOD-030 to include that rating updates from the Transmission |

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| | Owner require the TFC to reflect the change.<br><br>- R3.4 requires that a TOP include all modeling and topology for Facilities in the Reliability Coordinator Area. For a small TOP within a large RC, this may be overkill.<br><br>Response: The SDT feels that requiring the model to contain the facilities in the RC area will be required for consistent, reliable calculation of AFC. The standard drafting team feels that it will not be burdensome to supply such data even for a small TOP within a large RC. The team has added a statement saying, "Equivalent representation of radial lines and facilities161kV or below is allowed," which should help with the modeling.<br><br>R3.5 arbitrarily requires a model to include 3 contiguous busses from the tie-line into synchronously connected systems and R3.6 requires at least an equivalent representation further in than that. These are not appropriate or acceptable methods for determining modeling detail level. The two involved TSPs for the given transmission system and adjacent transmission system should determine the appropriate level of modeling detail needed in the adjacent transmission system.<br><br>Response: The SDT has changed this requirement to be consistent with MOD-028, which requires the modeling or equivalencing of adjacent Reliability Coordinator areas. This level of modeling detail provides some of the effects of the neighboring without burdening the Transmission Operator. However, additional modeling detail can be used.<br><br>This standard should not include any requirements on the Transmission Operator. R2 should be a requirement on the Transmission Service Provider. Ultimately, they will have to work with the TOP to identify the flowgates and it is in the best interest of the TOP to help the TSP but the requirement should not apply to the TOP. This drafting team should work with the appropriate drafting team developing TOP requirements to ensure that there is a requirement for the TOP to communicate limits to the TSP.<br><br>Response: The SDT believes that the functional model indicates this requirement is the responsibility of the Transmission Operator.<br><br>R3 should not apply to the TOP. It should apply to the TSP. The TSP should use system limit inputs such as SOL and IROL given by the TOP to determine TFC. Ultimately, R3 should be a simple requirement for the TSP to use the system limits determine by the TOP per FAC-014-1 standard to define the TFC. No sub-requirements are then required.<br><br>Response: The SDT believes that the functional model indicates this requirement is the responsibility of the Transmission Operator.<br><br>- R10 requires that all TSPs convert their AFCs and TFCs to ATC and TTC values. The IRC supports an allowance for entities whose tariffs do not use ATC and TTC to meet this requirement through a tool rather than manual calculations. There is no value added to the customer to have ATC and TTC values for transmission service that is sold on an AFC |

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<tr><th>Commenter</th><th>3. Comments on Requirements</th></tr>
<tr><td></td><td>and TFC basis. Therefore these TSPs should not be burdened with the added expense and effort to convert the values manually. The IRC proposes the following language, "The Transmission Service Provider shall convert or provide a tool to convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths."<br><br>Response: The language as written does not prohibit the use of a tool to perform this calculation.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Manitoba Hydro</td><td>R.3.5 of MOD-030-1, arbitrarily requiring modeling data and topology for at least three contiguous busses is too prescriptive. Standards should set out goals and use measures to determine if these goals were achieved. How the goals are best achieved are best determined by the Transmission Owner/Operator. If the goal is to improve loop flow, then the measure should be developed that ascertains loop flow improvement. A prescriptive number of busses does not insure that loop flow is appropriately captured.</td></tr>
<tr><td colspan="2">Response: The SDT has changed this requirement to be consistent with MOD-028, which requires the modeling or equivalencing of adjacent Reliability Coordinator areas. This level of modeling detail provides some of the effects of the neighboring without burdening the TO. However, additional modeling detail can be used.</td></tr>
<tr><td>MidAmerican Energy Electric Trading</td><td></td></tr>
<tr><td>Midwest ISO</td><td>MOD-001-1:<br><br>- R.3.3 of MOD-001-1 should read "The identity or a link to the identity of the Planning Coordinator…associated with each Flowgate…". Reasoning: Common practice is to include flowgates rather than all facilities. Also, the list of Flowgates may get updated often (monthly). We suggest including a link to the Flowgates. Having this link will reduce the burden of having to update the ATCID on a monthly basis.<br><br>Response: The Drafting Team has modified the requirement to require a list of Transmission Operators from which the Transmission Service Provider receives data for use in ATC calculations instead of requiring this information for each facility.<br><br>MOD-004-1:<br><br>- R4.2 of MOD-004-1 should be reworded as: "…simultaneously, or a methodology to meet resource adequacy criteria that assumes an aggregated need for CBM, or all firm ATC or AFC has been allocated…" Reasoning: Assuming each LSE (or group of LSE) submits its GCIR based on 1day/10year criteria, preserving the “sum” of all such requests is equal to planning according to such 1day/10year emergency happens in all LSEs (or groups of LSE) at the same time. In a large capacity sharing pool such as MISO, this is to plan way beyond 1day/10year criteria. We recognize the right of LSE having special requirement based on state requirement. However, the original lingual doesn’t allow MISO to continue its current methodology (“max” instead of “sum”) even if all LSEs agree to do so. An alternative could be allowed by the standard such that regional TSPs like ISO/RTOs that develop a consensus method with stakeholders of evaluating CBM needs on a regional basis may base CBM on LSE load forecasts and firm generation commitments, and have the CBM calculated by the TSP as necessary to ensure resource reliability criteria.<br><br>Response: The drafting team has modified the standard to include the concept of a Planned Resource Sharing Group.</td></tr>
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| | - R4.1.2.2 of MOD-004-1 should read "As a minimum standard, classify … greater than 3% on an OTDF Flowgate or 5% on a PTDF Flowgate as a significant impact".<br><br>Response: The drafting team has eliminated this requirement from the standard.<br><br>- For R4.2.2. of MOD-004-1, since AFC is determined from CBM, CBM for each Flowgate should not be dependent on AFC. CBM can be big enough to drive AFC to zero or negative. This simply means that resource adequacy criteria can't be met, and no capacity will be available on that Flowgate (which is what the original wording of this requirement was trying to do anyway). Therefore we believe CBM should not be set to AFC, it should be left at whatever value was calculated. Suggestion language: For Flowgates, Entities may use a static number, which requires its CBMID describe the procedure of utilizing CBM, or set the CBM for each Flowgate equal to the lesser of:<br><br>- For R4.3 and R5.3 of MOD-004-1, see the comment for R4.2.2. The same argument applies to these requirements.<br><br>- For R5.2 of MOD-004-1, see the comment for R4.2. The same rewording is recommended.<br><br>Response: The SDT has modified the standard such that it allows the Transmission Service provider to choose the manner in which they will handle CBM requests that exceed available capacity. The standard also requires a description of that choice to be included in the CBMID.<br><br>MOD-030-1:<br><br>- MOD-030-1, R2 should read "…Transmission Operator or Transmission Service Provider…" After hearing some industry comment that including this "or" (as we have in multiple comments) may not be possible in a standards requirement, we look to the team to determine how best to include some flexibility in which entity is required to meet the standard, to respect the varying distribution of work across these regions.<br><br>Response: The SDT believes that the NERC functional model indicates this to be the responsibility of the Transmission Operator.<br><br>- R3 of MOD-030-1 should read "The Transmission Service Provider shall use a Transmission model to determine…" And then an additional criteria bullet could be added that states "Contains data provided by the Transmission Operator, to the extent that it is available." the wording on this comment is very draft<br><br>Response: R3 has been modified to remove the TOP from determining AFC and R5.1 has been modified for the TSP to use the models provided by the Transmission Operator.<br><br>- R.3.5 of MOD-030-1, arbitrarily requiring modeling data and topology for at least three contiguous busses is too prescriptive. This requirement could be rewritten to as "Contains modeling data and topology agreed upon by each adjacent Reliability Coordinator Area and the Transmission Operator or the Transmission Service Provider." However it is worded, somehow the requirement has to be set based on the intention of improving loop flows, not getting to a certain number of busses. |

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| | Response: The SDT has changed this requirement to be consistent with MOD-028, which requires the modeling or equivalencing of adjacent Reliability Coordinator areas. This level of modeling detail provides some of the effects of the neighboring without burdening the TO. However, additional modeling detail can be used.<br><br>- R4. of MOD-030-1 needs to be rewritten. First, we believe NERC standard shouldn't intervene with how TSP treats PTP reservations. TSP has the best knowledge of their system and knows what treatment gives the best AFC forecast. Second, if this treatment has to be discussed anyway, we believe that having some flexibility is better than requiring the use of source/sink. For example, one transaction going across multiple OASIS will have the same source/sink along the path. Using source/sink could result in double-counting, triple counting, etc. Another example is that, in large TSP area such as MISO, OASIS POR/POD or Source/Sink can't represent real-time market central dispatch. Reservations/schedules only determine overall MISO interchange, not interchange for MISO internal BAs. In other cases, some other method may be more desirable. If getting the most accurate calculation (while not hindering transparency) is the intent of the team, then the way in which the reservation is modeled should not solely depend on the information in the request, but rather on a methodology that can be reviewed by everyone. Suggested language? (maybe in the same line as "a methodology that can be reviewed by everyone"<br><br>Response: The SDT believes that the requirement gives significant flexibility based on the model used to analyze the reservations. Note that "the market" could be an equivalence, depending on how the word is interpreted. The SDT has modified the language in 6.2, 6.3, 7.1, and 7.2 to address concerns with "double counting."<br><br>For R10. of MOD-030-1, the text describing "P" should read: "...as a minimum standard, a Flowgate is considered 'impacted' by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or 5% on a PTDF Flowgate".<br>Response: The SDT believes that an OTDF or PTDF greater than 3% is appropriate. |
| Response: Please see in-line responses. | |
| Modesto Irrigation District | MID supports the comments submitted by SMUD on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| MRO | - MOD-001, R1, should read "...Transmission Operator or Transmission Service Provider..." After hearing some industry comment that including this "or" (as we have in multiple comments) may not be possible in a standards requirement, we look to the team to determine how best to include some flexibility in which entity is required to meet the standard, to respect the varying distribution of work across these regions.<br><br>Response: The SDT believes that the NERC functional model indicates this to be the responsibility of the Transmission Operator.<br><br>- MOD-001-1 R1: The requirement to select one method for each path needs to be clarified. Some MRO members use the rated system path method for CA-CA hard-tie calculations and then use the flowgate method facilities expected to be congested. The requirement to translate AFC to ATC for each path could result in a conflict if the CA-CA path limit is based upon the rated path method when a flowgate limits the path rating when AFCs are converted to ATCs. The MRO recommends that the SDT clarify the requirement as necessary to explain how this conflict will be |

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| | resolved.<br><br>Response: The SDT believes that Transmission Operators and Transmission Service Providers will need to come to this determination on their own. It is the hope of the SDT that both numbers could be expected to be reasonably close. However, in any case, the SDT would expect that entities would use the most conservative value to maintain reliability of the system.<br><br>- MOD-001-1 R.3.3 should read "The identity or a link to the identity of the Planning Coordinator and Transmission Operator…associated with each Flowgate…". Reasoning: Common practice is to include flowgates rather than all facilities. Also, the list of Flowgates may get updated often (monthly). We suggest including a link to the Flowgates. Having this link will reduce the burden of having to update the ATCID on a monthly basis.<br><br>Response: This requirement has been modified to eliminate the reference to facilities.<br><br>- MOD-001-1 R3.6: The MRO does not understand what “allocation” is. The MRO asks that the SDT clarify this word in the standard.<br><br>Response: The SDT has clarified the meaning of “allocation” by in its requirement for detail about it within the ATCID in MOD-001. An example of allocation is the use of “Available Share of Total Flowgate Capability,” as is done as part of the PJM/MISO Joint Operating Agreement.<br><br>- MOD-001-1, R6, the method of notification should include an option for public posting such as OASIS.<br><br>Response: The intent of this requirement is to require the entity making the change to inform the entities affected by the change. Simply posting the information on OASIS does not meet this intent. Note that we are making this requirement more generic, and will allow methods other than e-mail.<br><br>- MOD-001-1, R10. 14 days can be too short when there are multiple requests pending. There should be a queue process. It is reasonable to request a response time for the first request in the queue, but not on all simultaneous requests.<br><br>Response: The time has been changed from 14 days to 30 days. Note that providers need not wait to build their data exchange systems until the data is requested; the intent of the 30 days is to allow for any necessary coordination details and access approvals to be taken care of prior to the beginning of the data exchange.<br><br>- MOD-001-1 R10: The extent of data to be provided upon request is potentially too extensive to be workable or justified.<br><br>Response: The SDT does not believe the data to be too extensive or not justified.<br><br>- MOD-001-1 R10: The requirement should be to only provide your own data. Otherwise there can be issues of confidentiality with providing third party data.<br><br>Response: The SDT has incorporated the suggested change.<br><br>- MOD-001-1 R10: There should be a restriction that it is only required to provide data used in AFC calculations. This may be implied but it should be made clear. |

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| | Response: The requirement now references that this is data "to be used in ATC calculations."<br><br>- MOD-001-1 R10.1: The need to provide transmission "additions and retirements" should be restricted to only those used in AFC calculations. The open planning process is the correct venue to request info on planned facilities, not the ATC standards.<br><br>Response: The SDT believes that all additions and retirements within an area may have a legitimate impact on ATC/AFC, and should be disclosed. This is not intended to circumvent any planning process.<br><br>- MOD-001-1 R10.4" "details" needs to be expanded upon. The MRO does not understand what this means.<br><br>Response: The SDT has eliminated the requirement for the details.<br><br>-MOD-001-1, R10.12. Since there is a requirement to provide this information in 14 days, this needs to be clarified to say that information that must be provided is the rules for calculating counterflow used in the calculation of ATCs, not the actual MW values because the MW would be too much data to provide in 14 days.<br><br>Response: The SDT has eliminated this requirement.<br><br>- MOD-004-1 does not seem to provide for those Transmission Service Providers who have a practice of maintaining zero CBM due to reserve sharing arrangements in which little outside assistance has been assumed in developing their historical generation reserve requirements. The MRO recommends that a requirement be added to MOD-004-1 outlining what descriptions must be provided in the CBMID to describe zero CBM practices such as under R3.1. For the SDT's information, MAPP historically has self provided its reserve requirements without outside assistance and therefore has historically set CBM to zero.<br><br>Response: Based on this comment, as well as the recent FERC Order 890A, the SDT has clarified the applicability of this requirement such that entities who do not use CBM need not comply.<br><br>- MOD-004, R3 and R4, A monthly value is extremely difficult to administrate and implement in the ATC calculation. Such a requirement will subject the TSP to significant increases in cost (the vendor has to provide new code and the frequency of TSP updates would drastically increase). GCIR calculation part has to do a lot more studies. Midwest ISO suggests leaving it to each region to decide on the time intervals.<br><br>Response: The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. We are requiring that entities update their CBM at least once a month to ensure that no unneeded CBM is still being held back from the market. The standard has been modified to clarify the intent of that section.<br><br>- MOD-004, R3.1 – This section should be updated to clarify what is meant to be requested. For example, it states "requested for each month for each year for the next ten year period." Do you really want 120 months worth of requests, or 12 monthly requests and 9 yearly? Suggested wording "for each month for the first 12 months and for each year for the remainder of the ten year period"<br><br>Response: The SDT has modified the language to of the requirement to be more clear. |

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| | - MOD-004, R3.2 – Why should LSE update every month if CBM is only calculated once per year? We suggest that these timelines be clarified.<br><br>Response: The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. We are requiring that entities update their CBM at least once a month to ensure that no unneeded CBM is still being held back from the market. The standard has been modified to clarify the intent of that section.<br><br>- MOD-004-1 R4.2 should be reworded as: "…simultaneously, or a methodology to meet Resource Adequacy criteria that assumes an aggregated need for CBM, or all firm ATC or AFC has been allocated…" Reasoning: Assuming each LSE (or group of LSE) submits its GCIR based on 1day/10year criteria, preserving the "sum" of all such requests is equal to planning according to such 1day/10year emergency happens in all LSEs (or groups of LSE) at the same time. In a large capacity sharing pool such as MISO, this is to plan way beyond 1day/10year criteria. We recognize the right of LSE having special requirement based on state requirement. However, the original lingual doesn't allow MISO to continue its current methodology ("max" instead of "sum") even though all LSEs agree to do so.<br><br>Response: The SDT chose this course of action because of potential conflicts with state or local regulations. If a state mandates that entity X rely on 200MW worth of external resources for generation adequacy, and mandates entity Y rely on 200MW as well, these two entities may make separate requests to the TSP, each requesting 200MW. If the TSP only grants 200MW of CBM, and a capacity emergency occurs that impacts both entities, then there will not be enough CBM. Rather than put the TSP and LSEs in this position, we are requiring the TSP grant what he is asked for, and giving LSEs the opportunity to make joint requests, directly or through a third party, so that aggregations such as you describe can occur – but only with the LSEs knowledge and consent. The SDT has modified the language to explicitly allow planned resource sharing groups which we believe will address your concern.<br><br>- MOD-004-1 R4.1.2.2 should read "As a minimum standard, classify … greater than 3% on an OTDF Flowgate or 5% on a PTDF Flowgate as a significant impact".<br><br>Response: The SDT has deleted this section of the requirement to address your concern.<br><br>- MOD-004-1 R4.2.2. - since AFC is determined from CBM, CBM for each Flowgate should not be dependent on AFC. CBM can be big enough to drive AFC to zero or negative. This simply means that resource adequacy criteria can't be met, and no capacity will be available on that Flowgate (which is what the original wording of this requirement was trying to do anyway). Therefore we believe CBM should not be set to AFC, it should be left at whatever value was calculated. Suggestion language: For Flowgates, Entities may use a static number, which requires its CBMID describe the procedure of utilizing CBM, or set the CBM for each Flowgate equal to the lesser of:<br><br>- MOD-004-1 R4.3 and R5.3 - , see the comment for R4.2.2. The same argument applies to these requirements.<br><br>- MOD-004-1 R5.2 - see the comment for R4.2. The same rewording is recommended. |

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| | Response: The SDT has modified the standard such that it allows the Transmission Service provider to choose the manner in which they will handle CBM requests that exceed available capacity. The standard also requires a description of that choice to be included in the CBMID.<br><br>- MOD-008-1 R1.1 indicates that one uncertainty that can be considered is "Aggregate Load forecast uncertainty (not included in determining generation reliability requirements)." The MRO understands that a concern is making sure that items are not double covered by CBM and TRM, however, this sub requirement is incorrect and needs to be modified because the same load forecast uncertainty will result in uncertainty in generation planning that may require a CBM amount--in other words we have to allow for additional transmission capacity to deliver generation reserves in an emergency when loads are higher. But that same load forecast uncertainty will result in uncertainty in the loadings on transmission facilities and will impact the need for having a margin to cover for loads on the system at all times. The MRO recommends that the SDT either delete the words "(not included in determining generation reliability requirements)" from the item or else revise the words to say something like the following which better describes what should be excluded, that is "(TRM is not to include impacts of load forecast uncertainty on CBM.)"<br><br>Response: The drafting team believes these to be two distinct values. TRM is based on the belief that the transmission system will be differently utilized due to variations in dispatch based on loads that are significantly deviating from forecasted values. In other words, it is likely that these impacts will be due to more internal generation being turned on to serve load. However, CBM is much more explicit, and is related to the need to import generation due to a capacity deficiency. In this case, the path that will be impacted may be significantly different than those impacted by a deviation in load forecast. To clarify, we have changed the wording slightly: "not included in determining generation reliability requirements for CBM."<br><br>There is nothing in the MOD 008 standard that precludes an entity for having different TRM's on different paths, or from excluding certain factors from TRM. If an entity's TRM method and CBM method would result in double counting in a manner not accounted not explicitly addressed in Mod 8, there is nothing that would prevent the entity from modifying its TRM method to eliminate the double counting.<br><br>- MOD-008-1 R1.2: The need to state that consistent assumptions are used for TRM as is used in the planning process needs to be clarified. The SDT should clarify that short-term TRM should be consistent with operational planning while long-term TRM should be consistent with long-term planning. The MRO recommends that the language here be modified to be similar to R8 of MOD-001-1 to say, "A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in ANY ASSOCIATED OPERATIONS STUDIES OR PLANNING STUDIES FOR THE TIME PERIOD STUDIED." The words in caps are the new words that are added in place of the words in the draft standard for that part of R1.2.<br><br>Response: The SDT has included the suggested wording.<br><br>- MOD-008, R1.5: "If TRM is zero for any of the time periods listed…..".<br><br>Response: The SDT has modified this requirement to indicate that if TRM is not used, a statement of that practice should be included.<br><br>- MOD-008-1 R3. and R4 call for certain responsible entities to provide information in seven days. This is not enough |

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| | time to allow for delays due to vacations and other absences. In smaller utilities, especially this seven days is not realistic. The MRO asks that the SDT increase this time and suggests 30 days as a more reasonable number.<br><br>Response: The team reviewed this requirement. Based on your comments and others the team made several changes that should address your concerns:<br>#1: R4 on the TSP was removed, it did not make sense for the TSP to serve as aggregator for the Transmission Operators material and would be burdensome on some TSP to have to respond to requests for information that is not theirs.<br>#2: R3 was modified to say make available instead of provide to better reflect the phrasing in other standards and to indicate that shipment of the material is not required, a posting such as a secure FTP site could be sufficient.<br>#3: R3 was modified to require a response to the requestor with the material requested, not a blanket response to all parties listed.<br>#4: R3 was modified to allow for 30 days instead of 7 days. While the material should be readily available, it is more common to allow 30 days for non critical information transmittal and this resolves the concern at some smaller entities over holidays and vacations.<br>#5: Due to the elimination of R4, R3's list of possible requestors was expanded.<br><br>- MOD-030-1, change R1 language to affect M1 regarding criteria used by Transmission OwnerR1, TSP should not be responsible for actively notifying changes made to criteria set by TO. Suggested wording is "… shall include … (ATCID) the practice or a link to the practice the TSP uses for adding Flowgates".<br><br>Response: The Transmission Service Provider is responsible for interacting with the Transmission Operator to ensure this information is available. The SDT did not restrict using a link to the TOP criteria for selection of Flowgates.<br><br>- MOD-030-1 R2.1 has a typo, the word "for" should be deleted from the requirement.<br><br>Response: The SDT has corrected this typographical error.<br><br>- MOD-030-1 R2.1.2 is too limiting in requiring that "at a minimum the first three limiting Elements/Contingency combinations within the Transmission Operator's system are included as Flowgates." The MRO believes there are smaller Transmission Operators with surrounding larger utilities with higher loaded facilities where this requirement would unnecessarily result in the establishment of additional flowgates. The MRO is not sure an across-NERC requirement for flowgate criteria is required; however, if the SDT gets comments to the contrary, the MRO suggests that the Transmission Provider be required to have documentation which includes an explanation for not using any of the three limitations. In this way, there is not a lot of needless work yet there is a provision which will result in protecting reliability. If TPs develop the documentation, if there are reliability issues, it will be obvious and the TPs will act to create the new flowgates.<br><br>Response: The requirement could create some unneeded flowgates, but the SDT feels that this is not overly burdensome to those using the flowgate methodology. In order to maintain reliability the SDT believes that the minimum of the first three limiting Elements/Contingency combinations within the Transmission Operator's system |

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| | being included as Flowgates is required.<br><br>- MOD-030-1, R2 should read "…Transmission Operator or Transmission Service Provider…"  After hearing some industry comment that including this “or” (as we have in multiple comments) may not be possible in a standards requirement, we look to the team to determine how best to include some flexibility in which entity is required to meet the standard, to respect the varying distribution of work across these regions.<br><br>Response: The SDT believes that the NERC functional model indicates this to be the responsibility of the Transmission Operator.<br><br>- MOD-030-1, requirement R.2.1.1. is redundant with the definition of Flowgate given in the "definitions" section.  This requirement should be removed, or at least reworded to read "…may be a Flowgate."<br><br>Response:  The SDT agrees.  We agree.  R.2.1.1 has been modified.<br><br>- MOD-030-1, R2.1.2, the phrase "first three limiting" is too prescriptive and should be removed. For example, if the most limiting first contingency transfer is a large value, say 10,000, adding first three limiting elements/contingency combinations is not necessary.  If the requirement can’t be deleted, we suggest adding wording that sets a transfer level such that the first three constraints that cause the FCITC to fall under that level will be captured.  Also, “source sink combinations” needs to be further defined as a calculation entity of any size could have thousands of these possible combinations.  Also, if this in-depth study is required, the frequency in R2.2 should be decreased (as this is a minimum standard).<br><br>Response: The requirement could create some unneeded flowgates, but the SDT feels that this is not overly burdensome to those using the flowgate methodology. In order to maintain reliability the SDT believes that the minimum of the first three limiting Elements/Contingency combinations within the Transmission Operator's system being included as Flowgates is required. The SDT has modified R2.1.1. and R2.1.2 to include the phrase, “up to the path capability”. The source sink has been changed to POR POD in R2.1.2. The frequency in R2.2 has been modified to annually. The source sink has been changed to POR POD in R2.1.2. The frequency in R2.2 has been modified to annually.<br><br>- MOD-030-1 R2.1.3:  Before the first “OR” the MRO recommends that a qualifier like “experiencing at least 24 instances of congestion” and “expected to be a congested facility in the planning horizon” to limit the instances in which parties have to post a flowgate.  If a facility has TLR because of some weird system condition not expected to occur again, it would be waste of time to post a flowgate for that.<br><br>Response: R2.1.3 has been modified to add “….and for which such invocation of an Interconnection-wide congestion management procedure is expected to reoccur within the next 12 months.”<br><br>- MOD-030-1 R2.2 requires that the list of Flowgates be updated on a quarterly basis.  Yet R2.4 requires that TFC only be updated on an annual basis.  The MRO recommends that R2.2 be changes to updating on an annual basis.  The quarterly basis is needless extra work.<br><br>Response: The drafting team agrees and changed the update period for internal flowgates to yearly.  The drafting |

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| | team has changed the update period for external flowgates to monthly.<br><br>- MOD-030-1, R2.3 rating issues, refer to comments from SRC, which says "MOD-030-1, R2.3 does not identify that TFC can be limited by an IROL but it should. If selling transmission service really requires development of a reliability standard, R2.4 should be modified to require updating the TFC any time the underlying determinants, such as facility ratings, change.".<br><br>Response: By definition, all IROLs are SOLs, and are therefore covered by the existing requirements.<br><br>- MOD-030-1 R2.3: The MRO is aware of some processes that require that regional groups to approve new flowgate TTCs prior to posting so as to have a regional reliability and equity review prior to posting the new flowgate TTCs. If a flowgate line rating increases, there can be a time-lag until the regional groups approve the new operating study and operating guide required before the new TTC can be posted. Some words are needed to allow for the time lag for regional review since it benefits reliability and equity.<br><br>Response: The SDT does not believe the time limits specified preclude any entity from doing such peer review prior to updates or changes. Note that "determination" is defined by the Transmission Operator; if such determination requires approvals prior to effectiveness, this is acceptable.<br><br>- MOD-030-1 R3 should read "The Transmission Service Provider shall use a Transmission model to determine…" And then an additional criteria bullet could be added that states "Contains data provided by the Transmission Operator, to the extent that it is available."<br><br>Response: The SDT has modified the standard to address this concern.<br><br>- MOD-030-1 R.3.5, arbitrarily requiring modeling data and topology for at least three contiguous busses is too prescriptive. This requirement could be rewritten to as "Contains modeling data and topology agreed upon by each adjacent Reliability Coordinator Area and the Transmission Operator or the Transmission Service Provider." However it is worded, somehow the requirement has to be set based on the intention of improving loop flows, not getting to a certain number of busses.<br><br>Response: The SDT has changed this requirement to be consistent with MOD-028, which requires the modeling or equivalencing of adjacent Reliability Coordinator areas.. This level of modeling detail provides some of the effects of the neighboring without burdening the TO.<br><br>- MOD-030-1 R4 needs to be rewritten. First, we believe NERC standard shouldn't intervene with how TSP treats PTP reservations. TSP has the best knowledge of their system and knows what treatment gives the best AFC forecast. Second, if this treatment has to be discussed anyway, we believe that having some flexibility is better than requiring the use of source/sink. For example, one transaction going across multiple OASIS will have the same source/sink along the path. Using source/sink could result in double-counting, triple counting, etc. Another example is that, in large TSP area such as MISO, OASIS POR/POD or Source/Sink can't represent real-time market central dispatch. Reservations/schedules only determine overall MISO interchange, not interchange for MISO internal BAs. In other cases, some other method may be more desirable. If getting the most accurate calculation (while not hindering transparency) is the intent of the team, then the way in which the reservation is modeled should not solely depend on the information in the request, but rather on a methodology that can be reviewed by everyone. Suggested language? (maybe in the same line as "a methodology that can be reviewed by everyone"<br><br>Response: The SDT believes that the requirement gives significant flexibility based on the model used to analyze the |

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| | reservations. Note that "the market" could be equivalence, depending on how the word is interpreted. We have modified the language in 6.2, 6.3, 7.1, and 7.2 to address concerns with "double counting."<br><br>- MOD-030-1 R5.1 indicates that the TSP is to include all expected outages, additions, and retirements in effect in the TSP's area, adjacent TSPs, and any TSPS with coordination agreements have been executed. The MRO believes this is a nice goal but the TSP cannot be liable for a penalty for failing to include all expected outages, additions, and retirements that it hasn't been told about. The MRO recommends that "and known" be added to the requirement.<br><br>Response: The SDT has incorporated the suggested word into the requirement.<br><br>- MOD-030-1, R5.1. This is not always the best practice. For example, while using PSS/E model, some outage remote to the TSP service area can cause the case to not solve and the TSP has to either use DC power flow solution or ignore the outage. The impact from ignoring a remote outage on the accuracy of AFC is much smaller than that from using DC power flow. The TSP has to temporarily block the outage to achieve overall better accuracy. Suggestion wording is "… have been executed, to the extent it helps improve the AFC calculation accuracy." Understanding that the ability to measure deviations may become an issue, the wording could be adjusted to state "… have been executed, except for any outages that, if included, would force the calculation into a less accurate solution technique." We realize that the suggested wording is not perfect, but we're hoping that the team understands our intention and can adjust it accordingly.<br><br>Response: R5 has been revised to provide additional flexibility. Language has been added to allow for outage processing rules to be specified in the ATCID.<br><br>- MOD-030-1 R5.1: The word "all" should be deleted. Only the one included in the calculation should be required.<br><br>Response: The SDT has modified the language to reference the limits of the model.<br><br>Also, same comment on the "additions and retirements" language. The need to provide transmission "additions and retirements" should be restricted to only those used in AFC calculations. The open planning process is the correct venue to request info on planned facilities, not the ATC standards.<br><br>Response: The SDT has modified the language to reference the limits of the model. This is not intended to circumvent the planning process, but to ensure the ATC process respects the planning efforts underway.<br><br>- MOD-030-1, R5.2. should add "to the extent they are available" to the end. Not all MISO third parties have that data available.<br><br>Response: The SDT believes that by including the phrase "as provided," we have allowed for entities to not use information they have not been provided.<br><br>- MOD-030-1 R6.1.3.1.1: Peak load forecast for the first 31 days needs to be clarified. The MRO is aware of some that prepare a peak load forecast only for the next 7-10 days. In such cases the load used in projections for days 11-31 is the monthly value. The accuracy of daily forecasts beyond the next 7-10 is questionable. Maybe the language should specifically allow this. |

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| | Response: This standard would require that those entities begin producing daily load forecasts for all 31 days. To accomplish this, they could provide days 8-30 with an identical load forecast based on that monthly value. Note that the SDT has removed the requirement for the forecast used to be a "peak" forecast, which may also address your concerns.<br><br>- MOD-030-1 R6.2: "impact" needs to be defined a bit more. Some MRO members define impact as something like 85% of positive impacts, 100% if the flowgate has had firm TLR. Also, "expected to be scheduled" should be clarified because some Transmission Providers include all reservation impacts in AFCs. The "expected" language adds a complexity that will be hard to meet and for that reason the language should be deleted.<br><br>Response: By "impact," the SDT means the amount of energy expected to flow on the flowgate due to the effects of the scheduled generation. The SDT has modified the "expected" language to clarify what is meant, which is the elimination of double counting due to partial path reservations.<br><br>- MOD-030-1 R6.3 and R6.4 provide a 3% but do not define what it is 3% of. The MRO recommends that the SDT add language to explain how it is calculated --what is the calculated in terms of percent of what. This also applies to R7.2 and R7.4 of the same standard.<br><br>Response: The SDT has modified the language to be clearer referring to distribution factor.<br><br>- MOD-030-1 R7.1: Again "impact" needs some more definition. Some presently use something like 50% counterflow in non-firm AFCs.<br><br>Response: By "impact," the SDT means the amount of energy expected to flow on the flowgate due to the effects of the scheduled generation.<br><br>Also, the language states that non-firm AFCs should only bring in non-firm reservations. The MRO believe this is wrong. Firm reservations NEED to be considered in non-firm AFCs.<br><br>Response: The language states that Non-firm ETC consists of only non-firm reservations (and other non-firm uses). However, the formula for determining AFC includes both the firm and non-firm ETCs, which the SDT believes addresses your concern.<br><br>- MOD-030-1 R8 refers to postbacks but no definition is provided. The SDT should either provide a NERC definition, repeat the NAESB definition, or paraphrase a definition. Without it, the MRO and other responsible entities are not sure what is the requirement.<br><br>Response: The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks.<br><br>- MOD-030-1, R8 and R9, "ATC" should be "AFC".<br><br>Response: The SDT has corrected this typographical error.<br><br>-MOD-030-1 R10 is not understandable. The MRO has no idea what is meant by this Requirement and how to |

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| | implement the requirement. The SDT should substantially increase the words that explain this requirement.<br><br>Response: The SDT has attempted to clarify the equations by incorporating the “P” term. However, the SDT believes this requirement as written to be the clearest way to express the requirement.<br><br>-MOD-030-1 R10., the text describing "P" should read: "...as a minimum standard, a Flowgate is considered 'impacted' by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or 5% on a PTDF Flowgate".<br><br>Response: The SDT believes that a OTDF or PTDF greater than 3% is appropriate.<br><br>- MOD-030-1 R10: In addition to the comments already supplied, explicit consideration of the concern raised above regarding those cases where a party uses CA-CA path limits to set hard tie limits and yet also posts flowgate limits where AFCs need to be converted to ATCs. The requirement to translate AFC to ATC for each path could result in a conflict if the CA-CA path limit is based upon the rated path method when a flowgate limits the path rating when AFCs are converted to ATCs. The MRO recommends that the SDT clarify the requirement as necessary to explain how this conflict will be resolved.<br><br>Response: The SDT believes that Transmission Operators and Transmission Service Providers will need to come to this determination on their own. It is the SDT’s hope that both numbers could be expected to be reasonably close. However, in any case, the SDT would expect that entities would use the most conservative value to maintain reliability of the system. |
| Response: Please see in-line responses. | |
| New Brunswick System Operator | |
| NorthWestern Energy (NWMT) | See comments below. |
| Response: Please see response below. | |
| NPCC Regional Standards Committee | MOD-001<br><br>1. R1: The reference to the Planning Coordinator’s planning area in R1 is not appropriate; the reference should be to the Transmission Operator’s operating area.<br><br>Response: The SDT has modified the standard to incorporate this change.<br><br>2. R3.3: Since this standard deals with short-term Transmission Service, the reference to Planning Coordinator should be removed from R3.3, R6.1 and R6.4<br><br>Response: Because ATC can impact months 12 and 13, the SDT believes the Planning Coordinator should be made aware of any such changes based on the descriptions in the functional model.<br><br>3. R3.3: This should be reworded to be clear that the TOP is providing input (TTC or TFC) to the TSP to perform ATC |

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| | calc. Also suggest removing reference to a 'tariff' since non-jurisdictional entities may not have a tariff. Suggest the following language: The identity of the Transmission Operators that provide data on each Posted Path for use by the Transmission Service Provider in calculating ATC.<br><br>Response: The SDT has modified the standard to address your concerns.<br><br>Acronyms TOP, TFC, and TSP need to be defined in the Background Information on p. 3. The abbreviation "calc." should be spelled out.<br><br>Response: The Background Information will not become part of the Standards, and as such is not being revised. The Drafting Team believes TOP, TFC and TSP have been adequately defined in the Standards or the NERC Glossary of Terms. The Drafting Team could not find the abbreviation "calc." referred to.<br><br>4. R4 and R5 should reference both the terms counter-schedules and counterflow throughout the requirements<br><br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>R9 (or at a minimum the Measure for R9) must be modified to be clear that if TSP can demonstrate that no inputs to the ATC calculation have changed that an update of a 'timestamp' on an ATC value is not required. Suggested options for the language in R9: "Each TSP shall update ATC at a minimum on the following frequency, except that if all inputs to ATC are unchanged no update is required:" OR "Each TSP shall update ATC at a minimum on the frequencies listed below. However, if all inputs to ATC are unchanged no update is required."<br><br>Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br><br>MOD-029<br><br>1. R1.10 refers to EHV without it being a defined term and different regions could define EHV to be different voltage levels; suggest one of the following actions be taken: (a) include the desired kV level of the BPS system in the standard, (b) remove the reference to EHV entirely, (c) add a NERC glossary term. EHV should be defined in the Background Information on p.3 and be understood to be applicable to and restricted to the BPS irrespective of that voltage level. That definition must also include the BPS voltage level it refers to.<br><br>Response: The SDT agrees, and has eliminated the use of EHV in the requirement.<br><br>2. R2 language could be interpreted that all N-2 contingencies must be considered in a TTC study. If the intent that the TTC study should consider all currently required planning criteria, a general reference should be made to the planning standards rather than try to summarize and reiterate those requirements here.<br><br>Response: The SDT agrees and has modified R2.1, R2.1.1 & R2.1.2 to address your concerns by removing reference |

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| | to N-0, N-1 & N-2.<br><br>3. R2.1.5 contains a very specific consideration for EHV contingencies to be considered in the TTC. Is there a reliability need for ALL regions to consider EHVs in this manner? If not, we suggest removing this requirement from the NERC standard, where it can be added in a more detailed regional standard if required by a particular region. EHV should be defined in the Background Information on p. 3; the definition must include the BPS voltage level it refers to.<br><br>Response: The SDT has eliminated this requirement in response to your concern. |
| Response: Please see in-line responses. | |
| NYISO | The NYISO joins in, and supports, the comments submitted by the ISO/RTO Council ("IRC") in response to this question. The NYISO also supports the comments submitted by the NPCC. In particular, the NYISO strongly supports the NPCC's request that requirement R9 under MOD-01 be revised to clearly establish that ATC values need not be updated when the inputs to the ATC calculation have not changed. The NYISO also supports the NPCC's proposed revisions to the language of R9.<br><br>Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br><br>The NYISO also has concerns on MOD-028 R3, R4 and R6 regarding the frequency of TTC calculations when inputs have not changed.<br><br>Response: The SDT believes the suggested time periods are not onerous, even if inputs have not changed.<br><br>Except as noted by the IRC and NPCC, the NYISO does not believe that any of the proposed ATC standards are technically incorrect, so long as they are interpreted with sufficient flexibility to accommodate transmission providers that do not offer physical reservation transmission service. |
| Response: Please see in-line responses. | |
| PacifiCorp | - PacifiCorp supports the WECC MIC MIS ATC Drafting Team December 14, 2007 comments suggested redraft language of R10 as follows:<br><br>- "R10. Upon request from another Transmission Service Provider, Planning Coordinator or Reliability Coordinator, each Transmission Service Provider shall provide from the below specified list, only that data requested and only that data already in existence and in the possession of the Transmission Service Provider from which that specified data is requested. Provision of all data is subject to confidentiality and security requirements."<br><br>In addition, PacifiCorp suggests that the following sentence be added to the above proposed language that states "The requirements of R10.1-R10.15 should not be interpreted as a comprehensive list of what is required to be included in an ATC calculation." |
| Response: Please see WECC MIC MIS ATC Drafting Team response.<br><br>The SDT believes that the individual MOD standards themselves describe the information that is to be used in an ATC calculation. R10 only | |

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| describes information to be shared with other entities. | |
| PJM Interconnection LLC | The requirements in MOD 1 to meet the update periods are not required to meet the reliability aspects of ATC implementation.<br><br>Response: We have modified the requirements in a way that may address your concern. We believe that a requirement to keep ATC numbers up-to-date and accurate is a reliability concern. The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br><br>MOD 4:<br><br>PJM disagrees with the essence of the proposed Mod 4-CBM standard. As currently constructed, the requirements treat CBM as if it is an energy quantity as opposed to a reliability margin. The proposed standard reads more like a procedure manual applicable to a single vertically integrated utility. The majority of load served in the US does not use the CBM as a product construct. PJM will suggest modifications that will better reflect CBM as a margin, not a commercial product, used to preserve the reliability of multiple LSEs through various reliability agreements. The suggested changes will preserve the ability of a single LSE to treat CBM as a product, but will refocus the discussion to better articulate the concepts used in a market environment.<br><br>Provisions need to be made to allow the flexibility of LSEs to aggregate and allow the planning to be handled by an ISO. There are conflicts with the PJM Reliability Assurance Agreement Amongst Load Serving Entities.<br><br>The GCIR definition recognizes the aggregation of LSEs and the requirements in MOD 4 do not. For example R1.1 specifies LSE as a single entity. The requirements do not provide for other methods of managing CBM both in planning and operationally. It is recognized that multiple LSEs may aggregate but the procedural requirements of R3 for instance are on a LSE specific basis. The standards must recognize FERC accepted practices for instance the definition and methods of addressing GCIR should recognize that the net CBM for an aggregate of LSEs may be less than the sum of the CBM needed for each LSE.<br><br>GCIR definition should recognize that the net CBM for an aggregate of LSEs may be less than the sum of the CBM needed for each LSE.<br><br>If these standards are to be as procedural/process specific as they are now written then alternate applications of CBM are necessary. Some examples include but are not limited to:<br><br>R1.1 The drafting team would need to add language to recognize processes such as PJM's IRM study as satisfying requirements to determine import requirements. For the group of LSEs with an aggregated need for CBM.<br><br>Language must be changed in the standard allowing flexibility to LSEs and Balance Authorities to apply different methods and procedures for instance:<br><br>R1.3 Remove the words "for a Load Serving Entity to request" would allow other entities or agents to act on behalf of LSEs.<br><br>R3 through R10 contain timeframes that would not apply when CBM is determined on differing intervals. This standard is too specific to processes implemented in specific regions. The GCIR and CBM may not change on these |

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| | intervals and these requirements would be inappropriate. These requirements do not recognize the practice implemented by groups of LSEs acting through a stakeholder process in the determination of area wide CBM and reserve margins.<br><br>Response: The SDT has made some modifications to address your and other entities concerns. The drafting team believes that the standards now will allow for the majority of the flexibility you describe while at the same time establishing a minimum requirement for other entities.<br><br>MOD - 008<br><br>R1.3 The TRM allocation method may include a process contained in the AFC or ATC calculator that overrides the base TRM value.<br><br>Response: The SDT does not see this statement to be in conflict with the standard.<br><br>R1.6 There is a need to implement a requirement for cases where the TRM applied differs from the calculation. Such a number should be provided to the RC with sufficient documentation for the RC to approve the TRM prior to implementation. These instances should be documented in the TRMID.<br><br>Response: As a calculation method has not been specified in the standard, the SDT does not believe this requirement to be necessary. If the number differs for the calculation, then the TRM methodology should incorporate the possibility of making such adjustments. |
| Response: Please see in-line responses. | |
| Progress Energy, Carolinas | MOD-28-1 R7, MOD-030-1 R2.1.3.1<br><br>The distribution factor/impact value used in the analysis of ATC impacting calculations should be consistent in all related processes. The value used in the process to approve transmission service should provide at least as accurate/granular results as the TLR process that is used to relieve congestion. The current TLR process uses a 5% impact, but there is discussion of using a 3% impact for non-firm curtailments. The ATC processes should not use an impact/distribution factor above 3%.<br><br>The 3% value is in MOD-004 -1 4.1.2.2, MOD-030-1 – R6.3, R6.4, R7.2, R7.4 and R10.<br><br>A 5% value is used in MOD-028-1 R7, MOD-030-1 R2.1.3.1.<br><br>The 5% impact or distribution values used in the Standards should be changed to 3% to be consistent across processes and Standard requirements, and to support the TLR process. |
| Response: The drafting team has discussed the distribution factors extensively and set them to appropriate levels. | |
| Public Service Commission of SC | |
| Public Utility District #2 of Grant County, Washington | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |

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| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Puget Sound Energy | See comments below. |
| Response: Please see response below. | |
| Salmon River Electric Cooperative | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Salt River Project | Please refer to answers to question Q6 for examples |
| Response: Please see Q6 for response. | |
| Santee Cooper | MOD028 R3.1 should read "For ..., and next-day on-peak TTCs". Remove intra-peak after next day. |
| Response: The SDT has corrected this typographical error. | |
| SERC ATCWG | MOD-028, Requirement R5 and MOD 030, Requirement R4, refer to the term "interface point" with the adjacent TSP. To meet this requirement, an entity must simulate an artificial source/sink at the interface point. It should utilize the adjacent TSP area as the source/sink.<br><br>Response: The SDT has modified the standard language to address this concern.<br><br>TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL (which are defined in other standards, e.g., IRO-004-1 and IRO-005-1). Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1, and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL. The following Violation Risk Factors listed as Medium in the proposed MOD-028-1, MOD-029-1, and MOD-030-1 should be listed as Lower: MOD-028-1, R2; MOD-028-1, R3; MOD-028-1, R9; MOD-028-1, R11; MOD-029-1, R1; MOD-029-1, R2; MOD-029-1, R5; MOD-029-1, R7; MOD-030-1, R3; MOD-030-1, R5; MOD-030-1, R6; and MOD-030-1, R9. For clarity, the risk factor for each requirement is suggested below:<br><br>In MOD-028-1, R2, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that using a model that does not meet the criteria specified in R2 can result in an TTC that is greater than the SOL or IROL Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system<br><br>In MOD-028-1, R3, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL. |

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| | Response: The drafting team disagrees. The SDT believes that using a data different than that specified in R3 can result in a TTC that is greater than the SOL or IROL. The SDT also believe that not adhering to the time frames specified can lead to an inaccurate ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system<br><br>In MOD-028-1, R9, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: drafting team disagrees. A violation of R9 can create a situation where the service sold is in excess of the TTC less the true ETC, resulting in over-scheduling of the path. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-028-1, R11, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: drafting team disagrees. A violation of R11 can create a situation where the service sold is in excess of the TTC less the true ETC, resulting in over-scheduling of the path. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-029-1, R1, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that using a model that does not meet the criteria specified in R1 can result in an ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-029-1, R2, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that not complying with R2 can result in a TTC that is greater than the SOL or IROL. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system. |

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| | In MOD-029-1, R5, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. A violation of R5 can create a situation where the service sold is in excess of the TTC less the true ETC, resulting in over-scheduling of the path. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-029-1, R7, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. A violation of R7 can create a situation where the service sold is in excess of the TTC less the true ETC and other components, resulting in over-scheduling of the path. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-030-1, R2, the Violation Risk Factor is listed as Lower; it should be listed as Medium. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The SDT has incorporated the suggested change.<br><br>In MOD-030-1, R3, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that using a model that does not meet the criteria specified in R3 can result in an ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-030-1, R5, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations |

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<tr><th>Commenter</th><th>3. Comments on Requirements</th></tr>
<tr><td></td><td>and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that not incorporating the information described in R5 can result in an ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-030-1, R6, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that not implementing R6 correctly can result in an ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.<br><br>In MOD-030-1, R9, the Violation Risk Factor is listed as Medium; it should be listed as Lower. TTC or TFC calculations and values can only be Medium or Higher Violation Risk Factors if the resulting TTC or TFC is greater than the SOL or the IROL. Therefore, the only requirements in the proposed MOD-028-1, MOD-029-1 and MOD-030-1 that should be Medium are MOD-028-1, R7, MOD-029-1, R4, and MOD-030-1, R2 which require that the TTC or the TFC be less than the SOL.<br><br>Response: The drafting team disagrees. The SDT believes that not implementing R9 correctly can result in an ATC that does not represent an accurate estimate of the state of the system once scheduled. Accordingly, the SDT believes a violation can have a negative effect on the reliability of the system.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Sierra Pacific Resources Transmission</td><td>(All standards should be checked for consistency in the use of the terms “calendar days” and “days.” In addition, these terms may differ between the Requirements and the corresponding VSLs. E.g. MOD-4, R4 specifies “calendar days” whereas the VSL for this requirement stipulates “days.”<br><br>Response: The SDT has made this language consistently use “calendar” days.<br><br>MOD-001 -<br><br>R1. and R2 States “…for each Posted Path per time period…” and “…values for the time periods listed…” respectively. The terms “time period” should be changed to “time horizon.” This locks the time window to a prescribed window and negates the ability to assign a random “time period.”<br><br>The use of the term "horizon" as used with the Violation Risk Factors is confusing because of the way "horizon" is used</td></tr>
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| | to calculate ATC. Always qualifying the horizon with ATC Horizon or VRF Time Horizon would help clarify the way this term is used.<br><br>Response: The SDT has intentionally avoided the use of the term "horizon" to avoid confusion with the compliance time horizons.<br><br>R3.3. This requirement needs to be broken into to different requirements and a change to the term Facility needs to be made as follows:<br><br>(New) R3.3 "The identity of the Planning Coordinator responsible for assessing the long term reliability of each path where ATC is calculated under the Transmission Provider's tariff."<br><br>(New) R3.X "The identity of the Transmission Operator responsible for the real time operating reliability of each path where ATC is calculated under the Transmission Provider's tariff."<br><br>Response: The Drafting Team has modified the requirement to require a list of Transmission Operators from which the Transmission Service Provider receives data for use in ATC calculations instead of requiring this information for each facility.<br><br>R3.6. The format of this sub-requirement does not match that of the other five sub-requirements ahead of it making the meaning unclear. Suggest the following:<br><br>"R3.6. A description of the methodology(ies) used to allocate ATC among multiple lines or sub-paths within a larger Posted Path, including where applicable, any methodology(ies) used to allocate ATC among multiple owners of a single path."<br><br>Response: The Drafting Team has clarified this requirement, incorporating the concepts suggested.<br><br>R4 and R5. "Counterflows" Requirements<br><br>R4 and R5 should be cut and counterflows should be addressed as subcomponents in MOD-028, R11 AND R12; MOD-029, R7 and R8; MOD-030, R8 and R9. Counterflows should be pasted into the MOD-028, MOD-029 and MOD-030 as the last element of requirements.<br><br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>R6 E-Mail requirement when ATCID, TRMID, or CBMID are made |

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| | Recommend this be sent to NAESB to develop a place on OASIS for posting when changes are made.<br><br>Response: This requirement is for notification to reliability entities when something that may impact them is changing, not disclosure to the public. NAESB will be addressing the latter; this requirement addresses the former.<br><br>R9 - "Update ATC"<br><br>Recommend R9 be removed and let NAESB handle ATC updates/postings in the NAESB standards.<br><br>Response: NAESB will be addressing the postings, but this requirement is intended to address the actual changing of the value that is used both internally and for coordinating with neighbors. NAESB may require more or less frequent updates.<br><br>If not removed, ATC should only need to be reviewed and updated if necessary. Change wording to "shall review and update if necessary…"<br><br>Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br><br>R10. Making Requested Data Available<br><br>Needs to be reworded and clearly state only data that already exists can be requested or must be provided and should have points broken down into sub requirements. Suggested rewording:<br><br>"R10. Upon request from another Transmission Service Provider, Planning Coordinator or Reliability Coordinator, each Transmission Service Provider shall only provide requested data from the specified list below, and only that data already in existence and in the possession of the Transmission Service Provider. Provision of all data is subject to confidentiality and security requirements. Each Transmission Service Provider providing information pursuant R10 shall do so:<br><br>RXX.1 Within fourteen days of a request<br><br>RXX.2 On the interval specified by the requesting entity, not to exceed more frequently than once per hour unless mutually agreed upon by the requestor and provider.<br><br>RXX.3 In the format in which the data exists at the time of the request, unless otherwise agreed upon by the requestor and provider.<br><br>Rxx.4 For the requested time period up to 13 months in the future."<br><br>Response: The requirement has been broken into subrequirements and the possible list of data has been converted to bullets. The requirement (currently R8) was reworded to improve the clarity (phrases such as “its own current data”, “in the format maintained by the Transmission Service Provider” have been added). Note that the posted standard required TFC and AFC only for “Flowgates considered by the Transmission Service Provider when selling transmission service” and this limitation has been retained.<br><br>R10.4. List of Data Elements that can be requested for NITS is too vague. Recommend changing to: |

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| | (New) R10.4 "Network Integration Transmission Service capacity on an aggregated basis."<br><br>Response: The SDT has incorporated the suggested language.<br><br>R10.13. There is a stray right parenthesis after the word "Margin."<br><br>Response: The SDT has corrected this typographical error.<br><br>MOD-004 -<br><br>R1.3. Scheduling Over CBM states that the Transmission Provider shall have a procedure that would allow a Load-Serving Entity (LSE) to request and schedule energy over (could be taken as in excess of the amount) that it has set-a-side for CBM. This requirement would be inconsistent and contradictory with the requirements that R3 has placed on the LSE with regards to the information that an LSE must provide prior to CBM being evaluated and set-a-side by the Transmission Provider if interpreted as such. Therefore a LSE should never be allowed to schedule energy over the amount of Transfer Capability set aside as CBM and suggest "over" to be changed to "on".<br><br>Response: The SDT has changed the words as suggested.<br><br>R2 CBMID Availability<br><br>The acronym "CBID" should be changed to "CBMID."<br><br>Response: The SDT has corrected this typographical error.<br><br>Requires a seven day turnaround time on providing the CBMID or other related information to requesting parties. We suggest a 14 day time period in which to allow the Transmission Provider to supply such information to requesting parties.<br><br>Response: The SDT has adjusted the standard to allow for thirty days,<br><br>R3 LSE Requirements for Requesting CBM<br><br>Describes the requirements placed on the LSE that is requesting CBM. In being consistent with the rest of the MOD there needs to be specific timelines that the LSE must adhere to if there application is deemed insufficient and requires the LSE to submit additional information to the Transmission Provider. We suggest a 14 day requirement, or clarification that if an LSE's application is deemed insufficient it shall be immediately rejected and the LSE shall be removed from the queue.<br><br>Response: There is no queue required in the standards for these requests. Timing requirements for responding to a request are provided. The SDT has modified the language to require that TSPs will need to include in their CBMID (as specified in R1.1) the disposition and handling of deficient requests.<br><br>R4.3. States that if during an evaluation of monthly ATC, additional firm capacity becomes available, the capacity shall be granted to CBM customers first. This requirement would appear to give CBM a preferential queue position over Conditional Firm, which appears to be a stark contrast to the requirements set forth in FERC Order 890 with regards to Conditional Firm queue position and the availability of new monthly firm ATC.<br><br>Response: The SDT has modified the standard such that it allows the Transmission Service provider to choose the manner in which they will handle CBM requests that exceed available capacity. The standard also requires a |

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| | description of that choice to be included in the CBMID.<br><br>R6 and Measure M9 Both give the Transmission Provider only five days to provide information to requesting parties, we recommend both sections be changed to ten business days or 14 calendar days.<br><br>Response: This requirement is simply the amount of time the provider has from the time the CBM is calculated to notify the requester. We believe five days is sufficient. The SDT has modified the language to reference calendar days.<br><br>R7.1. and R7.2. Refer to seven calendar days, we suggest that both requirements be changed to fourteen calendar days.<br><br>Response: The SDT have modified the standard to allow for thirty days.<br><br>MOD-029 -<br><br>R1.6. Suggest this bullet be deleted. This is already addressed in R2 wherein the modeling process is dictated. Please note in the Rated System Path methodology, "peak load forecasts" are not used to stress the system; rather, load and generation are simulated to stress the system to its greatest capacity. There are cases when the highest forecasted load may not stress the system to its greatest utilization – which is the goal of the R2 under the Rated System Path.<br><br>Response; The SDT has eliminated the word "peak" from the requirement to address this concern.<br><br>R2 The performance criteria defined in R2 might, at some point be at odds with the proposed TPL standard. While the drafting team may not want to have references to another standard, the risk in not doing so would be that either standard would get modified and possibly create a contradiction that could be impossible to meet. Hence, MOD-029-1 should reference TPL for purposes of performance criteria.<br><br>Response: The SDT agrees and has modified R2.1, R2.1.1 & R2.1.2 to address your concerns by removing reference to N-0, N-1 & N-2.<br><br>R2.1.3. Seems to contradict R2.1.2 regarding the facility ratings clause. All of R2.1 concerns n-0, 1 & 2 outages. R2.1.1 specifically refers to n-0 outages and R2.1.2 with n-1 & 2 outages. Further, R.2.1.2 requires "no Transmission Element modeled above its emergency rating" following an outage; R.2.1.1 requires no "Transmission Element above 100% of its continuous rating" for n-0. Then along comes R2.1.3 which basically says no element above its rating ever! I suggest striking R2.1.3. It's contradictory and excessive.<br><br>Response: The SDT has deleted this requirement.<br><br>R2.3 Suggest correcting "…as determined by R1.2.1…" to read "…as determined by R2.1."<br><br>Response: The SDT has corrected this typographical error.<br><br>R2.1.5. stating that a three-phase fault should be modeled on "all" busses could imply simultaneous faults at every point around a path. The intent is one fault at a time, on all surrounding busses. Replacing "all" with "each" would |

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| | make the intent clear.<br><br>The SDT has removed this requirement.<br><br>R5. The language describing Native Load should be changed from “reserved” to “allocated.” Allocated is the word most frequently used in conjunction with OASIS to describe this condition. The same change should apply to GF sub F.<br><br>The SDT has modified the standard to use the word “set aside.”<br><br>The language describing Grandfathered capacity includes the defined terms “Firm” and "Transmission Service." Use of these words as defined terms is inconsistent throughout the proposed standards. They should either be changed here to a lower case or all applicable areas in each proposed standard should be changed to the defined term.<br><br>Response: The SDT agrees and has made the changes for consistency.<br><br>MOD-030 -<br><br>An entity using both MOD-030 for some paths and MOD-029 for other paths that are adjacent to entities using MOD-029 need not study Flowgates beyond the intersecting cut plane of its interface as the ATC at the interface does not fall under MOD-30 but MOD-29. To prevent seams issues and unnecessary analysis the Team suggests the following rewrite(s):<br><br>MOD-30, R2.1.2. All first Contingency transfer analyses from all adjacent Balancing Authority source/sink combinations either: a) to at least the first three limiting Elements / Contingency combinations within the Transmission Operator’s system or b) to the interface of the adjacent Balancing Authority where the Transmission Operator utilizes the Rated System Path methodology whichever is applicable.<br><br>If adopted, this same concept would be applied to: MOD-30, R3.5, R3.6, R5.1, R7.2 and R7.4.<br><br>Response: The SDT changed R2.1.2 to reflect the requested change. With respect to R3.5 and R3.6, the SDT has changed this requirement to be consistent with MOD-028, which requires the modeling or equivalencing of adjacent Reliability Coordinator areas.<br><br>R6.1, R6.3, R6.4, R7.2, R7.4 have been addressed by adding the stipulation that impacts of other neighboring systems only have to be used if they’re impact is greater than what is used in the regional congestion management procedure. This allows for sparse networks that do not get impacted by neighboring transactions to ignore them. |
| Response: Please see in-line responses. | |
| Snohomish PUD | MOD -001<br><br>R3.2 – “counter-schedules” should be deleted and “counterflows” should be capitalized with the definition supplied above [Counterflow: the impact of schedules, reservations, or actual energy flows in the direction opposite to the constraint<br><br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and |

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| | we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules. With this approach we do not believe that a definition of counterflow is required.<br><br>R3.3 – We agree with BPA about removal of this requirement, as it would require extensive modification to existing databases without serving a great need.<br><br>Response: The Drafting Team has modified the requirement to require a list of Transmission Operators from which the Transmission Service Provider receives data for use in ATC calculations instead of requiring this information for each facility.<br><br>In addition we support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.<br><br>Response: Please see WEC MIC MIS ATC Drafting Team responses. |
| Response: Please see in-line responses. | |
| The Southeast Coalition | Please see list below.<br><br>Counterflow: MOD-001 (R4, R5.1).<br>Requirements R4 and R5.1 of MOD-001 set the impact of counterflow to 0% in the calculation of firm ATC/AFC based on reservations and/or schedules, and calculation of non-firm ATC/AFC based on reservations. These requirements are not only technically incorrect because they do not provide any justification for the 0% counterflow setting and do not require Transmission Service Providers (TSPs) to provide any analyses, work papers, statistical scheduling data, etc. to justify a 0% counterflow or any other setting in their ATC/AFC calculations, they are also inadequate because they do not meet Order 890 Cite 293. The Standard should ensure consistent modeling of counterflows and require TSPs to provide a justification, along with work papers and analyses, for the counterflow percentage used in their calculations of firm and non-firm ATC/AFC. Additionally, a measurement to ensure that TSPs comply with providing justification for their counterflow settings should be added to the Standard.<br><br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>Updating of ATC Models: MOD-030 (R3). Requirement 9.3 of MOD-001 states that, at a minimum, monthly ATC values should be updated once a week. However, requirement 3.3 of MOD-030 states that the monthly models used for calculating monthly ATCs should be updated at least once per month. Requirement 3.3 is inconsistent with requirement 9.3 because monthly models should be updated at the same frequency as the monthly ATC values are updated, i.e. once a week. Otherwise, monthly ATC values may be inaccurate. Consistent with Cite 301 of Order 890, the Standard must "require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the |

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| | system, e.g., generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities". The Standard, as proposed, is silent in regards to updating models and ATC values when a serious event such as the unplanned outage/return of a major transmission line occurs or a serious modeling error in ATC calculations is uncovered. In these situations, TSPs should be required to update models and ATC values as soon as practical rather than waiting for the scheduled update.<br><br>Response: The update time periods have been adjusted.<br><br>Adjacent Systems Representation: MOD-030 (R3.5, R3.6). Requirements 3.5 & 3.6 establish the scope of adjacent systems to be included in ATC calculations. These requirements do not specifically require that adjacent systems be represented in a realistic manner or updated at the same frequency as the TSP system. Including three contiguous buses of the adjacent systems, as R3.5 requires, will not ensure an accurate representation of adjacent systems in the AFC models. These requirements fail to satisfy Order 890 at Cite 311 "to produce accurate determinations of ATC…". Furthermore, the Standard does not have a measure to assess the validity of adjacent systems representation and limits itself to only check that adjacent systems are included in the model (MOD-030, M7).<br><br>In order to produce accurate ATCs, it is not enough to merely check that adjacent systems are included in the model. Instead, it is critical to validate the performance of these models on an on-going basis and ensure that adjacent systems are being properly updated in TSP models with data such as: load, generation profile, net interchange, transactions, and outages, provided by adjacent system entities.<br><br>Response: The SDT has changed this requirement to be consistent with MOD-028, which requires the modeling or equivalencing of adjacent Reliability Coordinator areas. This level of modeling detail provides some of the effects of the neighboring without burdening the TO.<br><br>MOD-001 provides the exchanging of data with external areas.<br><br>These standards assume accurate models and data are being exchanged. The validation of models and load forecast does not belong in this standard.<br><br>Use of PTDF term:<br><br>MOD-030 (R2.1.3.1) Requirement 2.1.3.1 refers to generators that have at least a 5% Power Transfer Distribution Factor (PTDF) impact on a flowgate. Rather than PTDF, the proper term in this circumstance is Transfer Distribution Factor (TDF) because the flowgate could be either a PTDF or OTDF flowgate. The TDF term covers both cases.<br><br>Response: The SDT has modified the requirement to include both PTDF and OTDF. |
| Response: Please see in-line responses. | |
| Southern Company Transmission | |
| SPP | No comment. |
| Tacoma Power | Tacoma Power supports the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |

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| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Tri-State Generation and Transmission Association | |
| WECC MIC MIS ATC TF Drafting Team | General Comments<br><br>All standards should be checked for consistency in the use of the terms “calendar days” and “days.” Of note, these terms may differ between the Requirements and the corresponding VSLs. E.g. MOD-4, R4 specifies “calendar days” whereas the VSL for this requirement stipulates “days.”<br><br>Response: The SDT has clarified that all days are to be “calendar days.”<br><br>MOD-01<br><br>R1. and R2. State “…for each Posted Path per time period…” and “…values for the time periods listed…” respectively. The term “time period” should be changed to “time horizon.” This makes the language consistent with 890.<br><br>Response: The Drafting Team did not use the phrase “time horizon” because that is a term that is used by NERC in the Standards to indicate how much time is available for mitigating a violation to the requirements, and could thus cause confusion. The Drafting Team did remove the reference to time period in R2 and specifically referenced R2 in R1 in an attempt to address your concern.<br><br>R3.3. The Team and those listed above suggest breaking the “R” into two pieces for clarity. The existing wording of being “associated” with each Facility is overly vague.<br><br>Response: The SDT has done as suggested.<br><br>(New) R3.3 “The identity of the Planning Coordinator responsible for assessing the long term reliability of each Facility under the Transmission Provider’s tariff.” (This verbiage comes from the NERC Functional Model. As an alternative to the word "Facility", "Posted Path" should be considered.)<br><br>Response: The SDT has eliminated the Planning Coordinator, based on the intent of the requirement.<br><br>(New) R3.X “The identity of the Transmission Operator responsible for the real time operating reliability of each Facility under the Transmission Provider’s tariff.” (This verbiage comes from the NERC Functional Model. As an alternative to the word "Facility", "Posted Path" should be considered.)<br><br>Response: The SDT has modified this requirement to more clearly describe the intent.<br><br>R3.6 The format of this sub-requirement does not match that of the other five sub-requirements ahead of it making |

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| | the meaning unclear. The Team and those listed above suggest the following rewording:<br><br>"R3.6. A description of the methodology(ies) used to allocate ATC among multiple lines or sub-paths within a larger Posted Path, including where applicable, any methodology(ies) used to allocate ATC among multiple owners of a single path."<br><br>Response: The SDT incorporated the suggested language, but changed "ATC" to "transfer capacity" to cover ATC, TTC, AFC, and TFC. Additionally, the SDT also added the phrase "or Flowgate."<br><br>R4 and R5. These describe how counterflows are to be dealt with even though counterflows as a subcomponent of ETCs are addressed in MOD-28, R11 and R12; MOD-29, R7 and R8, and MOD-30, R8 and R9. The Team and those listed above suggest MOD-01, R4/R5 should be "cut" from MOD-01 and "pasted" into each of the MODs 28, 29 and 30 so that the reader / Applicable Entity can see the self-contained algorithm requirements in each of those three methodologies rather than having to cross reference (hunt and peck) between 28/29/30 and MOD-01. Since counterflows are always the last element mentioned in 28/29/30, the Team and those listed above would suggest pasting the MOD-01 counterflow requirement into each standard as the last requirement in each.<br><br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>R10. The wording is difficult to follow and could be clearer as to which entity must provide what information. The Team and those listed above suggest the following rewrite without doing damage to the substance.<br><br>Suggested redraft:<br><br>"R10. Upon request from another Transmission Service Provider, Planning Coordinator or Reliability Coordinator, each Transmission Service Provider shall provide from the below specified list, only that data requested and only that data already in existence and in the possession of the Transmission Service Provider from which that specified data is requested. Provision of all data is subject to confidentiality and security requirements.<br><br>R10.1 et al<br><br>Keep the list of data as drafted except for R10.4. which is overly vague. Change R10.4 to read:<br><br>(New) R10.4 "Network Integration Transmission Service capacity on an aggregated basis."<br><br>ADD AN ADDITIONAL REQUIREMENT FOR CLARITY; BREAK THE EXISTING R10 INTO TWO PIECES:<br><br>RXX. Each Transmission Service Provider providing information pursuant R10 shall do so:<br><br>RXX.1 Within fourteen days of a request<br><br>RXX.2 On the interval specified by the requesting entity, not to exceed more frequently than once per hour unless mutually agreed upon by the requestor and provider.<br><br>RXX.3 In that format in which the data exists at the time of the request, unless otherwise agreed upon by the |

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| | requestor and provider.<br><br>Rxx.4 For the requested time period up to 13 months in the future.<br><br>Response: The SDT has redrafted the requirement to improve clarity, and has modified the language to incorporate the "aggregated" concept. The requirement has been broken into subrequirements and the possible list of data has been converted to bullets.<br><br>R10.13 There is a stray right parenthesis after the word "Margin."<br><br>Response: The SDT has corrected this typographical error.<br><br>MOD-04<br><br>R2 The acronym "CBID" should be changed to "CBMID."<br><br>Response: The SDT has corrected this typographical error.<br><br>MOD-29<br><br>R1.6. The Team and those listed above suggest this bullet be deleted. This is already addressed in R2 wherein the modeling process is dictated. In the RSP methodology, "peak load forecasts" are not used to stress the system; rather, load and generation are simulated to stress the system to its greatest capacity. There are cases when the highest forecasted load may not stress the system to its greatest utilization – which is the goal of Order 890 as addressed in R2 under the RSP.<br><br>Response: The SDT has eliminated the word "Peak" from the requirement.<br><br>R2.3 The Team and those listed above suggest correcting "…as determined by R1.2.1…" to read "…as determined by R2.1."<br><br>Response: The SDT has corrected this typographical error.<br><br>R5. The language describing Native Load should be changed from "reserved" to "allocated." Allocated is the word most commonly used in conjunction with OASIS to describe this condition. The same change should apply to GF sub F.<br><br>Response: The SDT has modified the standard to use the phrase "set aside."<br><br>The language describing Grandfathered capacity includes the defined terms "Firm" and "Transmission Service." Use of these words as defined terms is inconsistent throughout the proposed standards. They should either be changed here to a lower case or all applicable areas in each proposed standard should be changed to the defined term.<br><br>Response: These terms have been made consistently lower case.<br><br>MOD-30<br><br>MOD-01 allows an entity to select multiple methodologies to determine ATC. For example, an entity may elect to use Flowgates inside their affected area whereas they may also elect to use the Rated System Path methodology at the interface of their affected area. Under this scenario, the applicable entity need not study Flowgates beyond the |

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| | intersecting cut plane of its interface as the ATC at the interface falls not under MOD-30 but MOD-29. To prevent seams issues and unnecessary analysis the Team and those listed above highly recommend the following rewrite(s):<br><br>MOD-30, R2.1.2. All first Contingency transfer analyses from all adjacent Balancing Authority source/sink combinations either: a) to at least the first three limiting Elements / Contingency combinations within the Transmission Operator's system or b) to the interface of the adjacent Balancing Authority where the Transmission Operator utilizes the Rated System Path methodology.<br><br>This concept also applies to: MOD-30, R3.5, R3.6, R5.1, R7.2 and R7.4.<br><br>Response: The SDT changed R2.1.2 to reflect the requested change. With respect to R3.5 and R3.6, the SDT has changed this requirement to be consistent with MOD-028, which requires the modeling or equivalencing of adjacent Reliability Coordinator areas.<br><br>R6.1, R6.3, R6.4, R7.2, R7.4 have been addressed by adding the stipulation that impacts of other neighboring systems only have to be used if they're impact is greater than what is used in the regional congestion management procedure. This allows for sparse networks that do not get impacted by neighboring transactions to ignore them. |
| Response: Please see in-line responses. | |
| WestConnect Transfer Capability Workgroup | General<br><br>In General the WestConnect Teams agrees with the WECC Comments. In addition the WestConnect Team adds the following comments.<br><br>All of the MODs should be reviewed for consistency in terminology. In particular the terms "day" and "calendar days".<br><br>Response: The SDT has reviewed for consistency and specified all days as calendar days.<br><br>MOD-01<br><br>R4. and R5. Address how counter flows are dealt with in determining ATC. In MODs 28, 29 and 30 the use of counter flows are again addressed in the determining ATC. This leads to having to refer to two different documents when addressing counter flows. The WestConnect Team suggests using the WECC suggestion. WECC suggestion is "The Team suggests MOD-01, R5 should be "cut" from MOD-01 and "pasted" into each of the MODs 28, 29 and 30 so that the reader / applicable entity can see the self-contained algorithm requirements in each of those three methodologies rather than having to cross reference (hunt and peck) between 28/29/30 and MOD-01. Since counterflows are always the last element mentioned in 28/29/30, the team would suggest pasting the MOD-01 counterflow requirement into each standard as the last requirement in each."<br><br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>Requirement R10. should be rewritten to clarify that Transmission Service Provider is required to provide only the data requested and only the existing data that the Transmission Service Provider has possession of and in the format that |

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| | this existing data is in.<br><br>Response: The requirement has been reworded to improve the clarity as requested.<br><br>Change R10.4 so that the Transmission Service Provider provides Network Integration Transmission Service details on an aggregated basis.<br><br>Response: The SDT has changed the language as suggested.<br><br>MOD-04<br><br>The Team suggest changing R2. to "within seven days of the effective day of a change."<br><br>Response: The drafting team believes that the entities should be notified prior to any change is implemented and the standard has been modified accordingly.<br><br>MOD-08<br><br>For a system where the Rated System Path method is used to determine ATC, the Transmission Operator for a path with multiple owners only operates the path. The Transmission Owner gets its contractual share of the TTC. In addition it is responsible for all the ATC calculation and determining the TRM associated with it contractual share of the path. In MOD-08 as currently written the Transmission Operator is responsible for requirements R1., R2., R4. and R5.. The Team recommends that requirements R1., R2., R4. and R5. be rewritten to make this the responsibility of the Transmission Owner for entities using Rated System Path.<br><br>Response: The way entities are currently organized and the functional model do not always align due to the variety of organizational structures and the developmental state of the Functional Model and revising the functional model is beyond the scope of this team. There has been much discussion by the team on what part of the functional model is assigned to what requirements, and while the team would not claim to have found the perfect fit, the team does believe it has found the best fit for the current model.<br><br>Based on the model as currently written the team believes the Transmission Operator is the correct party. There is nothing in this requirement or the functional model that precludes the Transmission Operator from contracting with the Transmission Owners to provide the method, calculation, values and representation on this issue.<br><br>R.5 the Team suggest change "shall calculate" to "shall review and recalculate as necessary "<br><br>Response: As a result of the discussions subsequent to your comment the drafting team has split the old requirement R5 to two requirements (R4 and R5, the old R4 being deleted). This split allowed the team to review this item in more detail. The agreed to phrasing was<br><br>“Each Transmission Operator using TRM shall recalculate TRM values in accordance with the TRMID at least once every 13 months.”<br><br>Many utilities expressed the same concern you have on the phrase recalculation. A simple example may best express the teams standpoint on the phrase recalculation. Suppose a utility uses a formula in a spreadsheet to determine the TRM based on certain inputs. They perform their review and determined the inputs have not changed and therefore |

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<tr><th>Commenter</th><th>3. Comments on Requirements</th></tr>
<tr><td></td><td>the output value has not changed. In that case the report explaining the lack of change in inputs and a copy of the spreadsheet with an updated date would likely be sufficient.<br><br>MOD-29<br><br>R1.6. The bullet should be deleted. In the Rated System Path methodology "peak load forecast are not used to stress the system; rather, load and generation are simulated to stress the system. This is already addressed in R.2.<br>Response: The SDT agrees and has removed peak load forecast and replaced it with load forecast.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Western Area Power Administration – RMR</td><td>General Comments<br><br>All standards should be checked for consistency in the use of the terms “calendar days” and “days.” Of note, these terms may differ between the Requirements and the corresponding VSLs. E.g. MOD-4, R4 specifies “calendar days” whereas the VSL for this requirement stipulates “days.”<br><br>Response: The SDT has clarified that all days are to be “calendar days.”<br><br>The documentation overall is very wordy - starting with the "Proposed Effective Date." - need to cut down language throughout.<br><br>Response: The drafting team believes that in general, the language is appropriate, and accurately conveys the intention of the requirements. We have simplified where possible.<br><br>MOD-01<br><br>Posted Path Definition - "Any BA to BA interconnections." Most TPs in the Western Interconnection do not post BA-BA interconnections as "paths". Is the intent here to be interpreted as "if you post BA-BA paths" vs. you shall post all interconnections?<br><br>Response: A new term, ATC Path, has been defined for use in the NERC standards to avoid conflicting with a term presently defined by FERC and this term has been removed from the definition.<br><br>R1. and R2. State “…for each Posted Path per time period…” and “…values for the time periods listed…” respectively. The terms “time period” should be changed to “time horizon.” This locks the time window to a prescribed window and negates the ability to assign a random “time period.”<br><br>Response: The Drafting Team did not use the phrase “time horizon” because that is a term that is used by NERC in the Standards to indicate how much time is available for mitigating a violation to the requirements, and could thus cause confusion. The Drafting Team did remove the reference to time period in R2 and specifically referenced R2 in R1 in an attempt to address your concern.</td></tr>
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| | R3.3. The Team suggests breaking the "R" into two pieces for clarity. The existing wording of being "associated" with each Facility is overly vague.<br><br>Response: The SDT has done as suggested.<br><br>(New) R3.3 "The identity of the Planning Coordinator responsible for assessing the long term reliability of each Facility under the Transmission Provider's tariff." (As an alternative to the word "Facility", "Posted Path" should be considered.)<br><br>Response: The SDT has eliminated the Planning Coordinator, based on the intent of the requirement.<br><br>.(New) R3.X "The identity of the Transmission Operator responsible for the real time operating reliability of each Facility under the Transmission Provider's tariff." (As an alternative to the word "Facility", "Posted Path" should be considered.)<br><br>Response: The SDT has modified this requirement to more clearly describe the intent.<br><br>R3.6 The format of this sub-requirement does not match that of the other five sub-requirements ahead of it making the meaning unclear. The Team suggests the following rewording:<br><br>"R3.6. A description of the methodology(ies) used to allocate ATC among multiple lines or sub-paths within a larger Posted Path, including where applicable, any methodology(ies) used to allocate ATC among multiple owners of a single path."<br><br>Response: The SDT incorporated the suggested language, but changed "ATC" to "transfer capacity" to cover ATC, TTC, AFC, and TFC. Additionally, the SDT also added the phrase "or Flowgate."<br><br>R4 and R5. These describe how counterflows are to be dealt with even though counterflows as a subcomponent of ETCs are addressed in MOD-28, R11 and R12; MOD-29, R7 and R8, and MOD-30, R8 and R9. The Team suggests MOD-01, R5 should be "cut" from MOD-01 and "pasted" into each of the MODs 28, 29 and 30 so that the reader / applicable entity can see the self-contained algorithm requirements in each of those three methodologies rather than having to cross reference (hunt and peck) between 28/29/30 and MOD-01. Since counterflows are always the last element mentioned in 28/29/30, the team would suggest pasting the MOD-01 counterflow requirement into each standard as the last requirement in each.<br><br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>R10. The wording is difficult to follow and could be clearer as to which entity must provide what information. The Team suggests the following rewrite without doing damage to the substance. |

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| | Suggested redraft:<br><br>"R10. Upon request from another Transmission Service Provider, Planning Coordinator or Reliability Coordinator, each Transmission Service Provider shall provide from the below specified list, only that data requested and only that data already in existence and in the possession of the Transmission Service Provider from which that specified data is requested. Provision of all data is subject to confidentiality and security requirements.<br><br>R10.1 et al<br><br>Keep the list of data as drafted except for R10.4. which is overly vague. Change R10.4 to read:<br><br>(New) R10.4 "Network Integration Transmission Service capacity on an aggregated basis."<br><br>ADD AN ADDITIONAL REQUIREMENT FOR CLARITY; BREAK THE EXISTING R10 INTO TWO PIECES:<br><br>RXX. Each Transmission Service Provider providing information pursuant R10 shall do so:<br><br>RXX.1 Within fourteen days of a request<br><br>RXX.2 On the interval specified by the requesting entity, not to exceed more frequently than once per hour unless mutually agreed upon by the requestor and provider.<br><br>RXX.3 In the format in which the data exists at the time of the request, unless otherwise agreed upon by the requestor and provider.<br><br>Rxx.4 For the requested time period up to 13 months in the future.<br><br>R10.13 There is a stray right parenthesis after the word "Margin."<br><br>Response: The SDT has redrafted the requirement to improve clarity, and has modified the language to incorporate the "aggregated" concept. The requirement has been broken into subrequirements and the possible list of data has been converted to bullets.<br><br>D1.3 - data retention - why not make it all the same time period - say two years?<br><br>Response: These data retention requirements are driven by the requirements of the NERC compliance program.<br><br>MOD-04<br><br>R2 The acronym "CBID" should be changed to "CBMID."<br><br>Response: The SDT has corrected this typographical error.<br><br>R4.2.1 - Western interconnection puts reserve sharing requirements in TRM, not CBM.<br><br>Response: TRM is used for operating reserve and CBM is used for planning reserve and no double counting should occur. |

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| | MOD-29<br><br>R1.6. The Team suggests this bullet be deleted. This is already addressed in R2 wherein the modeling process is dictated. In the RSP methodology, "peak load forecasts" are not used to stress the system; rather, load and generation are simulated to stress the system to its greatest capacity. There are cases when the highest forecasted load may not stress the system to its greatest utilization – which is the goal of the R2 under the RSP.<br><br>Response: The SDT has eliminated the word "Peak" from the requirement.<br><br>General comment/question - does R.2 conflict with FAC-012?<br><br>Response: As part of the implementation, FAC-012 will be retired.<br><br>R2.3 The team suggests correcting "…as determined by R1.2.1…" to read "…as determined by R2.1."<br><br>Response: The SDT has corrected this typographical error.<br><br>R5. The language describing Native Load should be changed from "reserved" to "encumbered." Encumbered is the word most frequently used in conjunction with OASIS to describe this condition. The same change should apply to GF sub F.<br><br>Response: The SDT has modified the standard to use the phrase "set aside."<br><br>The language describing Grandfathered capacity includes the defined terms "Firm" and "Transmission Service." Use of these words as defined terms is inconsistent throughout the proposed standards. They should either be changed here to a lower case or all applicable areas in each proposed standard should be changed to the defined term.<br><br>Response: These terms have been made consistently lower case.<br><br>R6 - what is "non-firm capacity reserved for NITS"?<br><br>Response: This refers to network service from undesignated resources (i.e., Priority 6 non-firm Network).<br><br>D1.3 - why not require one retention time period - say two years?<br><br>Response: These data retention requirements are driven by the requirements of the NERC compliance program.<br><br>MOD-30<br><br>MOD-01 allows an entity to select multiple methodologies to determine ATC. For example, an entity may elect to use Flowgates inside their affected area whereas they may also elect to use the Rated System Path methodology at the interface of their affected area. Under this scenario, the applicable entity need not study Flowgates beyond the intersecting cut plane of its interface as the ATC at the interface falls not under MOD-30 but MOD-29. To prevent |

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| | seams issues and unnecessary analysis the Team suggests the following rewrite(s):<br><br>MOD-30, R2.1.2. All first Contingency transfer analyses from all adjacent Balancing Authority source/sink combinations either: a) to at least the first three limiting Elements / Contingency combinations within the Transmission Operator's system or b) to the interface of the adjacent Balancing Authority where the Transmission Operator utilizes the Rated System Path methodology.<br><br>If adopted, this same concept would be applied to: MOD-30, R3.5, R3.6, R5.1, R7.2 and R7.4.<br><br>Response: The SDT changed R2.1.2 to reflect the requested change. With respect to R3.5 and R3.6, the SDT has changed this requirement to be consistent with MOD-028, which requires the modeling or equivalencing of adjacent Reliability Coordinator areas.<br><br>R6.1, R6.3, R6.4, R7.2, R7.4 have been addressed by adding the stipulation that impacts of other neighboring systems only have to be used if they're impact is greater than what is used in the regional congestion management procedure. This allows for sparse networks that do not get impacted by neighboring transactions to ignore them. |

**4. The drafting team has proposed a set of measures and compliance elements for the standards. If there is a measure or compliance element that you believe is incorrect, please identify this for us, being as specific as possible with a suggestion for revising the language so it is correct.**

**Summary Consideration:** The majority of comments received were either corrections or clarifications. The SDT also made conforming changes in response to comments received in the other questions.

Some entities requested clarification that zero was an acceptable value for use in many of the calculations, The drafting team clarified this in the measures.

Some entities requested clarification regarding VSLs related to the use of facility ratings. The SDT clarified in the VLS that "an inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized."

The SDT made other minor corrections and clarifications as needed.

| Commenter | 4. Comments on Measures or Compliance Elements |
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| Alberta Electric System Operator | |
| Ameren Services | MOD-004-1<br>M8. "CBM has been used to determine a margin" should be reworded. CBM is a margin. Suggest eliminating "to determine a margin".<br>Response: The measure has been reworded such that this concern has been addressed.<br>D.1.3. R1 refers to CBMID not ATCID.<br>Response: The SDT has corrected this typographical error. |
| Response: Please see in-line responses. | |
| American Transmission Company | |
| Arizona Public Service Co. | Arizona Public Service Co. is in agreement with the WestConnect Comments and in general agreement with the WECC Comments.<br><br>Response: Please see the WECC MIC MIS ATC Drafting Team and WestConnect responses.<br>In addition the Arizona Public Service Co. adds the following comment.<br><br>MOD-001<br>The use of Counter Schedules to create firm ATC is of concern to APS. This practice could result in unreliable conditions to the interconnection if the counter flows do not occur. Due to the reliability concerns there should be a requirement for the Transmission Provider to provide documentation of actions that it will take if the Counter Flows do not occur.<br>Response: The standard no longer requires the use of counterschedules to create firm or non-firm ATC. |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| Response: Please see in-line comments. | |
| Avista Corporation | |
| Bonneville Power Administration | a. MOD-01<br>i. M9 – There is an unnecessary word "the" following the word "show" in the second line of the measure.<br>Response: The SDT has corrected this typographical error.<br><br>Additionally, the timeline(s) for responding to a request for data in R10 and M9 should be made consistent with one another – is it a requirement to respond to the request for data w/in 14 days or to begin to respond?<br>Response: The intent is for the TSP to make the first set of data available within 30 calendar days of a request and to update it on the scheduled frequency.<br><br>ii. VSL for R4 – The word "Firm" should be inserted before the word ATC as R4 only refers to Firm ATC.<br>iii. VSL for R5 – The word "Non-Firm" should be inserted before the word ATC as R5 only refers to Non-Firm ATC.<br>Response: R4 and R5 have been removed.<br>b. MOD-04<br>i. M1 – Suggested rewording: "Each Transmission Service Provider shall produce its CBMID evidencing inclusion of all specified information in R1." This approach should also be taken at M1 for MOD-08.<br>Response: The standards have been modified as suggested.<br>ii. M5 – line 3 states "…they it has based its CBM…" Please change to "…that it has based its CBM…"<br>Response: The SDT has corrected this typographical error.<br>iii. VSL for R2 – The acronym "CBID" should be changed to "CBMID."<br>Response: The SDT has corrected this typographical error..<br>iv. VSL for R10 – The VSL is unclear. The Team suggests it be rewritten to state, "The Transmission Service Provider failed to approve an Interchange Transaction Tag for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available."<br>Response: The standard has been modified as suggested.<br>v. D1.3 Data Retention – For clarity, the phrase "three calendar years" in the second through fifth bullets should be changed to "most recent three calendar years plus the current year."<br>Response: The standard has been modified as suggested.<br>c. MOD-08<br>i. M5 – M5 is missing he right parenthesis after the word "data" on the first line.<br>Response: The SDT has corrected this typographical error.<br>ii. VSL for R1 – In the Moderate Level column, change the phase "changes been" to "changes that have been".<br>Response: The SDT has corrected this typographical error.<br>d. MOD-29<br>i. M1 – M1 inaccurately calls for production of "models" used to derive TTC. As there are multiple conditions under MOD-29, R2 where a model does not dictate the predicate for TTC, M1 should be reworded to state "…shall produce the models, contracts, nomograms, reports or study results…" – this corresponding to:<br>1. Models in R2.1, R2.2. and R2.5<br>2. Contracts in R.2.3 and R2.6<br>3. Nomograms in R2.4 |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| | 4. Reports or studies in R2.7 and R2.8<br>Response: The drafting team has changed the measure to require "any" model used, which should address the concern expressed. Adding the items suggested would not be an appropriate change, as R1 does not require these items.<br>ii. M1.3 – The Team suggests correcting M1.3 from "…as stated in R1.1 through R.12…" to "…as stated in R1.1 through R1.12…"<br>Response: The SDT has corrected this typographical error.<br>iii. M4 – If "M1" above is adopted, M4 is duplicative of M1 and should be deleted.<br>Response: M4 has not been deleted because the change to M1 was not made as suggested.<br>iv. VSL for R4 – An SOL does not exist for every Posted Path. This VSL should be amended by changing the words "the SOL" in the High and Severe columns to read "any SOL". This makes the wording of the Requirement consistent with the wording of the Measure.<br>Response: The wording has been changed to "any associated" SOL.<br>v. VSL R5, R6, R7, R8 – These VSLs call for only a "severe" determination. They also mandate that the TSP "use" all the elements defined. However, the TSP will not "use" all the defined elements if they are not applicable. Thus, if a TSP does not "use" all elements defined because all the elements were not applicable – the TSP is in violation for not including null elements in its calculation. The Team suggests these be rewritten to state: "The Transmission Service Provider did not use all affected elements as defined in…." This approach should help clarify that "zero" as an integer is an acceptable entry and that only those variables "affected" need be reported or acted upon.<br>Response: The SDT agrees, and all standard have had their measures modified to indicate the use of a zero is not by itself a violation. |
| Response: Please see the detailed in-line responses. | |
| British Columbia Transmission Corporation | 1. MOD-029-1, M4 and Compliance, 1.3 Data Retention, 4th bullet - The reference to R2.7 should be R2.6 (i.e. should be R2.1 through R2.6). There are no models, reports, or study results required by R2.7. Therefore, there is no point in having a Measure and a Compliance Process looking to see if models, reports, or study results have been produced and retained.<br>Response: We have modified the measure to address this concern.<br>2. MOD-029-1, M7 - Should the reference be to R7 and R8? R6 does not require the use of TTC.<br>Response: Yes. The reference has been changed.<br>1. MOD-029-1, M7 - The reference to R.1.2 is not clear. Should this reference be to R2?<br>Response: Yes – Yes. The reference has been changed. |
| Response: Please see detailed in-line responses. | |
| Clearwater Power Company | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| ColumbiaGrid, Inc. | [Intentionally left blank.] |
| | |
| Consumers Power, Inc. | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Duke Energy | - MOD-001-1, M8 should say "recalculated" rather than "updated".<br>Response: The measure has been changed as suggested.<br>- MOD-001-1, VSLs for R10 should increase based upon increasing the time allowed to 30 days for making data available under R10 (see comment 3 above). Suggest Moderate VSL of 30 - 45 days, High VSL of 47 - 75 days, and Severe VSL of more than 75 days.<br>Response: The timing in the requirement has been changed from 14 days to 30 days and the VSLs have been changed accordingly. |
| Response: Please see detailed in-line responses. | |
| Entergy Services Inc. | MOD-001-1 M5 - copies of dated electronic email for notification does not ensure that the email has been received by the receiving party. Other mediums should be included or receipt of the email notification should be required as a measure.<br>Response: "Dated electronic mail message" has been removed from the requirement and listed as an example in what is currently M4.<br><br>MOD-001-1 M6 - Reference to "such as demonstration" is unclear as to what is included in "demonstration" so parenthetical reference should be deleted.<br>Response: The intent is to allow the provider to show the fact that the document has been made available.<br><br>MOD-001-1 M9 - Extra "the" from line 2 between the words "show" and "its" should be deleted.<br>Response: The SDT has corrected this typographical error.<br><br>MOD-004-1 M3 - The measure should also include group of LSEs with aggregated need for CBM as provided in R3.<br>Response: The measure has been changed as suggested.<br>MOD-004-1 First bullet under Data Retention should refer to CBMID rather than ATCID.<br>Response: The SDT has corrected this typographical error.<br><br>MOD-004-1 Violation Risk Factors - Correct typos in row for R2 "CBID" to be changed to "CBMID".<br>Response: The SDT has corrected this typographical error.<br><br>MOD-008-1 M2 - In case SDT removes reference to CBM as Entergy suggested above, SDT should remove reference to CBMID in this measure also.<br>Response: The team did not adopt the earlier proposal, therefore the Measure is not adopted.<br><br>MOD-008-1 M5 - In case SDT changes frequency or TRM calculation to 12 months as Entergy suggested above, SDT should make corresponding change in M5.<br>Response: The team did not adopt the earlier proposal, therefore the Measure is not adopted.<br><br>MOD-028-1 M9 - Correct typo in line 3 from "its" to "it".<br>Response: The SDT has corrected this typographical error.<br><br>MOD-029-1 M2 - Correct typo in line 3 from "ACTID" to "ATCID". |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| | Response: The SDT has corrected this typographical error.<br>MOD-030-1 Violation Risk Factors - Correct typo in cells under Lower VSL, Moderate, and High VSL for R2 to change from "is" to "it" in last paragraph.<br>Response: The SDT has corrected this typographical error. |
| Response: Please see detailed in-line responses. | |
| EPSA | |
| ERCOT | |
| Fall River Rural Electric Cooperative, Inc. | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| FirstEnergy Corp. | 1. MOD-001-1: Measure M2 - Change typographical error at the end of the measure that currently reads "(R1)" to "(R2)".<br>Response: The SDT has corrected this typographical error.<br><br>2. MOD-001-1: Measure M7 should not include the Transmission Operator. The TOP is not responsible for calculating the ATC, TTC, or AFC.<br>Response: MOD-028 Area Interchange Methodology and MOD-029 Rated System Path Methodology assign responsibility for calculating TTC to the Transmission Operator.<br><br>3. MOD-001-1: VSL-Severe for R2 incorrectly includes the Transmission Operator. This requirement is only applicable to the Transmission Service Provider.<br>Response: The Drafting Team has incorporated this change.<br><br>4. Per our rewording suggestions in Question 3 and Question 6, several measures and compliance elements must be reviewed and revised by the SDT.<br>- E.g., MOD-030-1: Measure M7 - Per our rewording suggested in Question 3 for Requirement R3, M7 should be reworded as follows: "The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to support the AFC calculated by the Transmission Service Provider contains the information specified in R3."<br>Response: The Drafting team has ensured that the Measures are consistent with the final Requirements. |
| Response: Please see detailed in-line responses. | |
| Flathead | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| FRCC | MOD 001: M8 (referencing R9) should be revised to require proof of updates only when the information posted needs to be changed. For Example: "The Transmission Service Provider shall provide evidence (such as logs or data) that it has updated the hourly, daily and monthly ATCs on at least the minimum frequencies specified in R9 when those ATC values have changed. |
| Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation. | |
| Georgia Transmission Corporation | MOD-001-1, R9, Lower VSL says "For Hourly, not calculated within 5hrs". MOD-001-1, R9, Medium VSL says "For Hourly, not calculated in more than 5 hours but not more than 10 hours". This language appears to allow a TSP to not calculate for 4:59 hours, while not calculating for 5 hours is a Lower VSL and more than 5 hours is a Medium VSL. We suggest that the MOD-001-1, R9, Lower VSL should be re-written to say "For Hourly, not calculated in more than 2 hours but not more than 5 hours".<br>Response: The language has been modified to address this concern.<br>MOD-028-1, M5 requires Transmission Operators to "provide copies of contracts" without stating the entities that can receive (potentially) commercially sensitive "copies of contracts". MOD-028-1, M5 should state "The Transmission Operator shall make available, only to authorized individuals that have executed a Confidentiality Agreement and that are performing official RRO audit activities, copies of contracts that contain requirements to allocate TTCs to show that any contractual allocations of TTC were respected as required in R5.2. Transmission Operators may redact the copies of the contracts to omit commercially sensitive information."<br>Response: This measure is related only to compliance, and all standard confidentiality agreements would apply. |
| Response: Please see detailed in-line responses. | |
| Hydro One Networks | |
| Hydro-Québec TransÉnergie (HQT) | 1. VSL for MOD-028 R2 and R3 are is not clear if the 'errors' that are allowed are for a given TTC study or the allowed cumulative 'errors' since the last audit? (this language should also be clarified on comparable VSLs in MOD-029 and MOD-030).<br>Response: The "errors" would apply for the period being audited. The SDT has clarified in MOD-028 and MOD-030 that "An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized."<br><br>"Are is" in the first sentence needs to be corrected.<br>The SDT has corrected this typographical error.<br><br>2. If suggestions in Question 3 and 6 are accepted, the associated Measures and VSLs will also need to be updated accordingly.<br>Response: The SDT has reviewed the Measures and VSLs and update them as appropriate. |
| Response: Please see in-line comments. | |
| IESO | MOD-001:<br><br>If the SDT accepts our comments in (3) above, then the following Measures should be revised: |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| | M1: changed to reflect new requirement language accordingly.<br>M7: Split this measure into two to reflect the split of R8 into two requirements.<br>M10: This measure needs to be reworded for clarity, as follows: "The Transmission Service Provider shall provide a copy of the dated request for ATC data as well as evidence to show it responded to that request (such as logs or data) within fourteen calendar days of receiving a request, and the requested data items were made available in accordance with R10."<br><br>Response: M1 has been changed to reflect the change in R1. The former R8 (currently R6) was not split, therefore no change has been made to the former M7 (currently M6). The former M10 (currently M9) has been reworded as requested.<br><br>MOD-004:<br><br>Assuming the above comments are accepted,<br>M2: Need to be changed to reflect posting on the OASIS.<br>M7: Need to change Transmission Planner to Transmission Service Provider.<br>M9: Remove Transmission Planner from this measure.<br>VSL for R1 should be changed to be associated with the number of elements (R1.1 to R1.3) not included.<br>Response: M2, M7, M9 - The above comments were not accepted. VSL for R1 – The VSL has been modified to address your concern.<br><br>MOD-008:<br><br>Assuming the above comments are accepted,<br>M4: Need to be changed to reflect posting on the OASIS.<br>VSL for R1 should be changed to be associated with the number of elements (R1.1 to R1.4) not included.<br>Response: M4 - The above comments were not accepted. VSL for R1 – The VSL has been modified to address your concern.<br><br>MOD-030<br><br>The Violation Risk Factor for R3, R5, R6, and R8 should be changed from Medium to Lower. In order for these requirements to have a medium VRF, according to the VRF criteria in Drafting Team Guidelines, they would have to directly affect the electrical state or capability of the bulk electric system or ability to effectively monitor and control the bulk electric system or in the planning time frame, or if violated, could under emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of capability of the bulk electric system. There is no direct link from this requirement because selling transmission service does not affect actual flows. The transmission service would have to be scheduled by the customer which he may not do and then the schedule has to be approved by all TPs on the path, and source and sink BA. These entities have tools that allow them to determine if a schedule should flow and the Reliability Coordinator acts as a backstop. When the RC issues a TLR, Interchange Distribution Calculator even reallocates and halts new schedules during regardless of how long ago the transmission service was sold. Thus, several other activities have to occur or fail to occur to impact directly the BES and thus, there is no direct link. |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| | Response: The SDT believes there is a direct link. Overselling of the system can lead to an SOL violation. While it is true that there are steps to mitigate such violations, this does not change the fact that an inaccurate ATC can increase the risk of those situations occurring. |
| Response: Please see in-line responses. | |
| ISO/RTO Council (IRC) | For MOD-001:<br>If the SDT accepts our comments in (3) above, then the following Measures should be revised:<br>M1: changed to reflect new requirement language accordingly.<br>M7: Split this measure into two to reflect the split of R8 into two requirements.<br>M10: This measure needs to be reworded for clarity, as follows: "The Transmission Service Provider shall provide a copy of the dated request for ATC data as well as evidence to show it responded to that request (such as logs or data) within fourteen calendar days of receiving a request, and the requested data items were made available in accordance with R10."<br>Response: M1 has been changed to reflect the change in R1. The former R8 (currently R6) was not split, therefore no change has been made to the former M7 (currently M6). The former M10 (currently M9) has been reworded as requested.<br><br>MOD-004:<br>Assuming the above comments are accepted,<br>M7: Need to change Transmission Planner to Transmission Service Provider.<br>M9: Remove Transmission Planner from this measure.<br>VSL for R1 should be changed to be associated with the number of elements (R1.1 to R1.3) not included.<br>Response: M7, M9 - The above comments were not accepted. VSL for R1 – The VSL has been modified to address your concern.<br><br>MOD-008:<br>Assuming the above comments are accepted,<br>VSL for R1 should be changed to be associated with the number of elements (R1.1 to R1.4) not included.<br>Response: The VSL has been modified to address your concern.<br><br>MOD-29<br>M1.<br>M1 inaccurately calls for production of “models” used to derive TTC. As there are multiple conditions under MOD-29, R2 where a model does not dictate the predicate for TTC, M1 should be reworded to state “…shall produce the models, contracts, nomograms, reports or study results…”<br><br>Corresponding to:<br>1) Models in R2.1, R2.2. and R2.5;<br>2) Contracts in R.2.3 and R2.6;<br>3) Nomograms in R2.4;<br>4) Reports or studies in R2.7 and R2.8. |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| | Response: The drafting team has changed the measure to require "any" model used, which should address the concern expressed. Adding the items suggested would not be an appropriate change, as R1 does not require these items.<br><br>M1.3<br>We suggest correcting M1.3 from "…as stated in R1.1 through R.12…" to "…as stated in R1.1 through R1.12…"<br>Response: The SDT has corrected this typographical error.<br><br>M4.<br>If "M1" above is adopted, M4 is duplicative of M1 and should be deleted.<br>Response: M4 has not been deleted because the change to M1 was not made as suggested.<br>VSL R5, R6, R7, R8<br>These VSLs call for only a "severe" determination. They also mandate that the TSP "use" all the elements defined. However, the TSP will not "use" all the defined elements if they are not applicable. Thus, if a TSP does not "use" all elements defined because all the elements were not applicable – the TSP is in violation for not including null elements in its calculation.<br><br>We suggest these be rewritten to state: "The Transmission Service Provider did not use all affected elements as defined in…." This approach should help clarify that "zero" as an integer is an acceptable entry and that only those variables "affected" need be reported or acted upon.<br>Response: The SDT agrees, and all standard have had their measures modified to indicate the use of a zero is not by itself a violation.<br><br>MOD-030<br>The Violation Risk Factor for R3, R5, R6, and R8 should be changed from Medium to Lower. In order for these requirements to have a medium VRF, according to the VRF criteria in Drafting Team Guidelines, they would have to directly affect the electrical state or capability of the bulk electric system or ability to effectively monitor and control the bulk electric system or in the planning time frame, or if violated, could under emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of capability of the bulk electric system. There is no direct link from this requirement because selling transmission service does not affect actual flows. The transmission service would have to be scheduled by the customer which he may not do and then the schedule has to be approved by all TSPs on the path, and source and sink BA. These entities have tools that allow them to determine if a schedule should flow and the Reliability Coordinator acts as a backstop. When the RC issues a TLR, the Interchange Distribution Calculator even reallocates and halts new schedules regardless of how long ago the transmission service was sold. Thus, several other activities have to occur or fail to occur to impact the BES and thus, there is no direct link.<br>Response: The SDT believes there is a direct link. Overselling of the system can lead to an SOL violation. While it is true that there are steps to mitigate such violations, this does not change the fact that an inaccurate ATC can increase the risk of those situations occurring. |
| Response: Please see in-line responses. | |
| Manitoba Hydro | |
| MidAmerican | |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| Energy Electric Trading | |
| Midwest ISO | |
| Modesto Irrigation District | MID supports the comments submitted by SMUD on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| MRO | |
| New Brunswick System Operator | |
| NorthWestern Energy (NWMT) | The use of the term "horizon" in the violation risk labels has caused some confusion because of its use in ATC horizons (different time periods for which ATC is calculated in a specific manner). |
| Response: This terminology has been used consistent with NERC's compliance definitions, which are beyond the scope of this drafting team to change. | |
| NPCC Regional Standards Committee | 1. VSL for MOD-028 R2 and R3 are is not clear if the 'errors' that are allowed are for a given TTC study or the allowed cumulative 'errors' since the last audit? (this language should also be clarified on comparable VSLs in MOD-029 and MOD-030).<br>Response: The "errors" would apply for the period being audited. The SDT has clarified in MOD-028 and MOD-030 that "An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized."<br><br>"Are is" in the first sentence needs to be corrected.<br>Response: The SDT was unable to find the reported error.<br>2. If suggestions in Question 3 and 6 are accepted, the associated Measures and VSLs will also need to be updated accordingly.<br>Response: The SDT has reviewed the Measures and VSLs and update them as appropriate. |
| Response: Please see in-line comments. | |
| NYISO | The NYISO joins in, and supports, the comments submitted by the IRC in response to this question. The NYISO also supports the comments submitted by the NPCC.<br><br>Except as noted by the IRC and NPCC, the NYISO does not believe that any of the proposed measures or compliance elements are incorrect based on its expectation that NERC will interpret the ATC standards in a way that accommodates the needs of transmission providers that do not offer physical reservation transmission service.<br><br>If, however, NERC were to interpret the standards in a manner that was inconsistent with the use of FERC-approved non-physical forms of transmission service then the proposed compliance and sanction requirements would be inappropriate, inequitable, and unlawful. The NYISO does not believe that this is NERC's intent. In any event, NERC should not develop standards, or interpret them in a way, that would expose transmission providers to enforcement action for implementing tariffs that have been approved by FERC, and that Order No. 890 does not require be changed, simply because their tariffs differ from the standard Order No. 890 model. |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| Response: Paragraph 160 of Order 890 provides ISOs and RTOs the means through which they can request to be exempted from the requirements of the Order, and NERC has similar provisions through which exemptions from the requirements of this standard may be pursued. These standards do not address the selling of service, and instead only apply to the determination of ATC. | |
| PacifiCorp | |
| PJM Interconnection LLC | Violation Severity Levels<br><br>NERC Standards should be developed to assure reliability. Standard business practices related to fair market practices should be developed and implemented by NAESB.<br><br>PJM supports the IRC comment that in order for "requirements to have a medium VRF, according to the VRF criteria in Drafting Team Guidelines, they would have to directly affect the electrical state or capability of the bulk electric system or ability to effectively monitor and control the bulk electric system or in the planning time frame, or if violated, could under emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state of capability of the bulk electric system."<br><br>Further, a Violation Severity Level should be a measure of the potential impact to reliability. If a violation does not impact reliability, there should not be a VSL assigned at all.<br><br>PJM agrees with SERC comments that violation levels for TFC should only be moderate or higher if they exceed an SOL or IROL.<br>Response: The SDT disagrees. Errors in the determination of AFC or ATC can result in unintentional overscheduling, which can result in violations of SOLs.<br>The VSLs set in the MOD standards are not consistent with the definitions the VSL definition in the Violation Severity Limit Definitions Table in Figure 1 of "Violation Severity Levels Development Guidelines Criteria October 10, 2007" (VSL Guidelines). The definition in the VSL Guidelines defines a Moderate Violation (VSL 2) as "non-compliant with respect to one significant element within the requirement." For example, MOD-030-1 sets the Severe VSL for R3 as "The Transmission Operator did not update the Transmission model per the schedule specified in R3," which is based on a violation of a single significant element. This clearly falls under the definition of a moderate VSL per the VSL Guidelines. The entire set of Violation Severity Levels in the MOD standards needs to be revised per the VSL Guidelines.<br>Response: The VSL guidelines are intended to serve as guidelines, not requirements. The drafting team has endeavored to make the VSLs consistent with the guidelines while at the same time ensuring an accurate accounting of the violation severity. |
| Response: Please see detailed in-line responses. | |
| Progress Energy, Carolinas | |
| Public Service Commission of SC | |
| Public Utility District #2 of Grant County, | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| Washington | |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Puget Sound Energy | The use of the term "horizon" in the violation risk labels has caused some confusion because of its use in ATC horizons (different time periods for which ATC is calculated in a specific manner). |
| Response: This terminology has been used consistent with NERC's compliance definitions, which are beyond the scope of this drafting team to change. | |
| Salmon River Electric Cooperative | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Salt River Project | Please refer to answers to question Q6 for examples |
| Response: Please see Q6 for response. | |
| Santee Cooper | |
| SERC ATCWG | Revise MOD-028-1, M5 to the following: The transmission operator shall describe in its ATCID the requirement to allocate TTC and show that any allocations of TTC were respected as required in R5.2. |
| Response: | |
| Sierra Pacific Resources Transmission | The SPR companies are in support of lowering the Violation Risk Factors and Violation Severity Levels as specifically commented on by SERC. At best all Violation Risk Factors should be LOW, as none of these requirements pose risk to the reliability of the interconnected Bulk Electric System, and are only commercial in nature. (Please refer to the response to Q5 below regarding the lack of applicability of these Standards to the reliability of the BES.)<br>Specific:<br>MOD-01<br>M9<br>There is an unnecessary word "the" following the word "show" in the second line of the measure.<br>Response: The SDT has corrected this typographical error.<br><br>VSL for R4.<br>The word "Firm" should be inserted before the word ATC as R4 only refers to Firm ATC.<br>Response: R4 has been deleted.<br><br>VSL for R5.<br>The word "Non-Firm" should be inserted before the word ATC as R5 only refers to Non-Firm ATC.<br>Response: R5 has been deleted.<br>MOD-04<br>M1<br>Suggested rewording: "Each Transmission Service Provider shall produce its CBMID evidencing inclusion of all specified information in R1." This approach should also be taken at M1 for MOD-08.<br>Response: The measure has been changed as suggested.<br>M5 |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| | M5, line 3 states "…they it has based its CBM…" Please change to "…that it has based its CBM…"<br>Response: The SDT has corrected this typographical error.<br>VSL for R2<br>The acronym "CBID" should be changed to "CBMID."<br>Response: The SDT has corrected this typographical error.<br>VSL for R10<br>The VSL is unclear. We suggest that it be rewritten to state, "The Transmission Service Provider failed to approve an Interchange Transaction Tag for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available."<br>Response: The VSL has been changed as suggested.<br>D1.3 Data Retention<br>For clarity and consistency, the phrase "three calendar years" in the second through fifth bullets should be changed to "most recent three calendar years plus the current year."<br>Response: The suggested change has been implemented.<br>MOD-08<br>M5<br>M5 is missing the right parenthesis after the word "data" on the first line.<br>Response: The SDT has corrected this typographical error.<br>VSL for R1<br>In the Moderate Level column, change the phrase "changes been" to "changes that have been".<br>Response: The SDT has corrected this typographical error.<br>MOD-29<br>M1.<br>M1 inaccurately calls for production of "models" used to derive TTC. As there are multiple conditions under MOD-29, R2 where a model does not dictate the predicate for TTC, M1 should be reworded to state "…shall produce the models, contracts, nomograms, reports or study results…"<br><br>Corresponding to:<br>1) Models in R2.1, R2.2. and R2.5;<br>2) Contracts in R.2.3 and R2.6;<br>3) Nomograms in R2.4;<br>4) Reports or studies in R2.7 and R2.8.<br>Response: The drafting team has changed the measure to require "any" model used, which should address the concern expressed. Adding the items suggested would not be an appropriate change, as R1 does not require these items.<br>M1.3<br>The Team suggests correcting M1.3 from "…as stated in R1.1 through R.12…" to "…as stated in R1.1 through R1.12…"<br>Response: The SDT has corrected this typographical error.<br>M4.<br>If "M1" above is adopted, M4 is duplicative of M1 and should be deleted.<br>Response: M4 has not been deleted because the change to M1 was not made as suggested VSL for R4.<br>An SOL does not exist for every Posted Path. This VSL should be amended by changing the words "the SOL" in the |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| | High and Severe columns to read "any SOL". This makes the wording of the Requirement consistent with the wording of the Measure.<br>Response: The wording has been changed to "any associated" SOL.<br>VSL R5, R6, R7, R8<br>These VRFs call for only a "severe" determination. They also mandate that the TSP "use" all the elements defined. However, the TSP will not "use" all the defined elements if they are not applicable. Thus, if a TSP does not "use" all elements defined because all the elements were not applicable – the TSP is in violation for not including null elements in its calculation.<br><br>The SPR companies suggest these be rewritten to state: "The Transmission Service Provider did not use all affected elements as defined in…." This approach should help clarify that "zero" as an integer is an acceptable entry and that only those variables "affected" need be reported or acted upon.<br>Response: The SDT agrees, and all standard have had their measures modified to indicate the use of a zero is not by itself a violation. |
| Response: Please see detailed in-line responses. | |
| Snohomish PUD | We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| The Southeast Coalition | |
| Southern Company Transmission | MOD-028 M5 is inappropriate. There is no reliability need to provide copies of contracts which may in themselves be difficult to interpret. R1.3 should be changed to read as follows. "Any provisions for calculating allocations of TTC." M5 should be changed to read as follows. "The Transmission Service Providers' ATCID includes provisions for the allocation of TTC." |
| Response: The SDT believes that it is important that the details of the allocation contracts be understood such that the allocations can be verified as being respected. | |
| SPP | No comment. |
| Tacoma Power | Tacoma Power supports the comments of the WECC MIC MIS ATC Drafting Team in regard to this question. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| Tri-State Generation and Transmission Association | |
| WECC MIC MIS ATC TF Drafting Team | General:<br>The Team and those listed above are in support of changing the Violation Risk Factors as specifically commented on by SERC.<br>Response: Please see responses to SERC.<br><br>Specific: |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| | MOD-01<br>M9<br>There is an unnecessary word "the" following the word "show" in the second line of the measure.<br>Response: The SDT has corrected this typographical error.<br><br>VSL for R4.<br>The word "Firm" should be inserted before the word ATC as R4 only refers to Firm ATC.<br>Response: R4 has been deleted<br>VSL for R5.<br>The word "Non-Firm" should be inserted before the word ATC as R5 only refers to Non-Firm ATC.<br>Response: R5 has been deleted.<br>MOD-04<br>M1<br>Suggested rewording: "Each Transmission Service Provider shall produce its CBMID evidencing inclusion of all specified information in R1."<br>This approach should also be taken at M1 for MOD-08.<br>Response: The measure has been reworded as suggested.<br>M5<br>M5, line 3 states "…they it has based its CBM…" Please change to "…that it has based its CBM…"<br>Response: The SDT has corrected this typographical error.<br>VSL for R2<br>The acronym "CBID" should be changed to "CBMID."<br>Response: The SDT has corrected this typographical error.<br>VSL for R10<br>The VSL is unclear. The Team suggests it be rewritten to state, "The Transmission Service Provider failed to approve an Interchange Transaction Tag for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available."<br>Response: The VSL has been rewritten as suggested.<br>D1.3 Data Retention<br>For clarity and consistency, the phrase "three calendar years" in the second through fifth bullets should be changed to "most recent three calendar years plus the current year."<br>Response: The change has been implemented.<br>MOD-08<br>M5<br>M5 is missing the right parenthesis after the word "data" on the first line.<br>Response: The SDT has corrected this typographical error.<br>VSL for R1<br>In the Moderate Level column, change the phrase "changes been" to "changes that have been".<br>Response: The SDT has corrected this typographical error.<br>MOD-29<br>M1.<br>M1 inaccurately calls for production of "models" used to derive TTC. As there are multiple conditions under MOD-29, R2 where a model does not dictate the predicate for TTC, M1 should be reworded to state "…shall produce the |

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<tr><td>WestConnect Transfer Capability Workgroup</td><td>The WestConnect Team is in support of lowering the VRFs as proposed in the SERC comments.</td></tr>
<tr><td colspan="2">Response: Please see response to SERC comments.</td></tr>
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| Commenter | 4. Comments on Measures or Compliance Elements |
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| Administration – RMR | Response: Please see responses to SERC.<br><br>Specific:<br>MOD-01<br>M9<br>There is an unnecessary word "the" following the word "show" in the second line of the measure.<br>Response: The SDT has corrected this typographical error.<br><br><br>VSL for R4.<br>The word "Firm" should be inserted before the word ATC as R4 only refers to Firm ATC.<br>Response: R4 has been deleted<br><br><br><br>VSL for R5.<br>The word "Non-Firm" should be inserted before the word ATC as R5 only refers to Non-Firm ATC.<br>Response: R5 has been deleted.<br><br><br>M5 - R5 is incorrect reference.<br>Response: The SDT has corrected this typographical error.<br><br>MOD-04<br>M1<br>Suggested rewording: "Each Transmission Service Provider shall produce its CBMID evidencing inclusion of all specified information in R1."<br>This approach should also be taken at M1 for MOD-08.<br>Response: The measure has been reworded as suggested.<br>M5<br>M5, line 3 states "…they it has based its CBM…" Please change to "…that it has based its CBM…"<br>Response: The SDT has corrected this typographical error.<br>VSL for R2<br>The acronym "CBID" should be changed to "CBMID."<br>Response: The SDT has corrected this typographical error.<br>VSL for R10<br>The VSL is unclear. The Team suggests it be rewritten to state, "The Transmission Service Provider failed to approve an Interchange Transaction Tag for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available."<br>Response: The VSL has been rewritten as suggested.<br>D1.3 Data Retention<br>Why not require one retention timeframe - say two years?<br>Response: These timeframes are based on NERC Compliance criteria, which varies based on the entities being |

| Commenter | 4. Comments on Measures or Compliance Elements |
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| | discussed.<br><br><br>MOD-08<br>M5<br>M5 is missing the right parenthesis after the word “data” on the first line.<br>Response: The SDT has corrected this typographical error.<br>VSL for R1<br>In the Moderate Level column, change the phrase “changes been” to “changes that have been”.<br>Response: The SDT has corrected this typographical error.<br>MOD-29<br>M1.<br>M1 inaccurately calls for production of “models” used to derive TTC.  As there are multiple conditions under MOD-29, R2 where a model does not dictate the predicate for TTC, M1 should be reworded to state “…shall produce the models, contracts, nomograms, reports or study results…”<br><br>Corresponding to:<br>1) Models in R2.1, R2.2. and R2.5;<br>2) Contracts in R.2.3 and R2.6;<br>3) Nomograms in R2.4;<br>4) Reports or studies in R2.7 and R2.8.<br>Response: The drafting team has changed the measure to require “any” model used, which should address the concern expressed.  Adding the items suggested would not be an appropriate change, as R1 does not require these items.<br>M1.3<br>The Team suggests correcting M1.3 from “…as stated in R1.1 through R.12…” to “…as stated in R1.1 through R1.12…”<br>Response: The SDT has corrected this typographical error.<br>M4.<br>If “M1” above is adopted, M4 is duplicative of M1 and should be deleted.<br>Response: M4 has not been deleted because the change to M1 was not made as suggested<br>M1.2 and M1.3 are redundant - remove one.<br>Response: M1.3 has been changed to not be redundant with M1.2.<br><br>M7 - reference to R.1.2 seems incorrect.<br>Response: The SDT has corrected this typographical error.<br>M8.1 and M9.1 are redundant - remove one.<br>Response: While the language appears redundant, it applies to different requirements.<br><br><br>VSL for R4.<br>An SOL does not exist for every Posted Path.  This VSL should be amended by changing the words “the SOL” in the High and Severe columns to read “any SOL”.  This makes the wording of the Requirement consistent with the |

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| | wording of the Measure.<br><br>VSL R5, R6, R7, R8<br>These VSLs call for only a "severe" determination. They also mandate that the TSP "use" all the elements defined. However, the TSP will not "use" all the defined elements if they are not applicable. Thus, if a TSP does not "use" all elements defined because all the elements were not applicable – the TSP is in violation for not including null elements in its calculation.<br><br>The Team suggests these be rewritten to state: "The Transmission Service Provider did not use all affected elements as defined in…." This approach should help clarify that "zero" as an integer is an acceptable entry and that only those variables "affected" need be reported or acted upon.<br>Response: The SDT agrees, and all standard have had their measures modified to indicate the use of a zero is not by itself a violation. |
| Response: Please see in-line responses. | |

**5. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?**

**Summary Consideration:** Most comments did not see any conflicts.

Some entities expressed concern with the impact that CBM will have with regard to rates. The drafting team modified the standards to allow for more flexibility, but in general did not agree that the requirements specified had impacts on rate-making.

Some market operators requested clarification that the standards were not forcing any particular market design. The SDT agreed and clarified this, and in some cases provided examples how a market operator and its customers would comply with the standards.

Some entities disagreed with the assertion that these standards have reliability impact. The SDT responded consistent with the responses to those entities that made similar comments in Q3.

Some entities pointed out that the SDT had not addressed the FERC directive to create methods for addressing situations where TSRs from a specific generator exceed the capability of that generator. The drafting team discussed this requirement in detail, and was unable to find a clear-cut practice that would not either 1.) harm open access by denying service, or 2.) harm reliability by ignoring the impact of potential schedules.

The SDT made other minor corrections and clarifications as needed.

| Commenter | Yes | No | 5. Comments on Conflicts |
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| Alberta Electric System Operator | | | |
| Ameren Services | | ☑ | |
| American Transmission Company | | ☑ | |
| Arizona Public Service Co. | | ☑ | |
| Avista Corporation | | | |
| Bonneville Power Administration | | ☑ | This response, however, is based on the understanding that BPA's statutory requirements to serve the load of other federal entities (i.e. the Corp of Engineers and the Bureau of Reclamation) are sufficiently accommodated within the GF or OS components of the ETC calculation in MOD-029 and the GF component of the ETC calculations in MOD-030. If these variables were not intended to accommodate non-contracted statutory obligations of this nature, please modify the ETC calculations to accommodate these obligations (see suggested modifications provided in earlier comments). |
| Response: The SDT believes you are correct, and that the GF and OS terms will address your needs. | | | |
| British Columbia Transmission | | ☑ | |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| Corporation | | | |
| Clearwater Power Company | | ☑ | |
| ColumbiaGrid, Inc. | | | [Intentionally left blank.] |
| Consumers Power, Inc. | | ☑ | |
| Duke Energy | ☑ | | As proposed, MOD-004-1 would require monthly updates of CBM requests, and monthly reallocation of CBM upon changes that affect the amount of CBM available. Paragraphs 257 and 258 from FERC Order No. 890 require that CBM set-aside be reflected in rates for point-to-point transmission service, such that point-to-point customers do not subsidize CBM for other customers. CBM values will have to be "locked down" to develop and make the rate filing, which FERC may take 60 days to approve. This defines a timing issue which suggests that CBM updates be made significantly less frequently than monthly, perhaps annually. Also, R6.1 includes a provision to request a system impact/facilities study, which suggests customers could pay for upgrades to create CBM. However CBM is a margin and not a transmission service as defined by FERC, so there is no clearly defined mechanism for charging customers for such upgrades. Detailed observations and comments on MOD-004-1 are as follows:<br>Observations:<br><br>1. CBM requests should be evaluated in queue order, along with other OASIS requests for service and should be evaluated comparable with other firm requests (NAESB is developing these business practices).<br><br>Response: The SDT has modified the standard such that it allows the Transmission Service provider to choose the manner in which they will handle CBM requests that exceed available capacity. The standard also requires a description of that choice to be included in the CBMID.<br><br>2. In order to manage Rate filings to accommodate Order 890 paragraphs 257 and 263, CBM values must, at some point, be “locked in” prior to the filing.<br>Response: The SDT believes there may be some complexity in the implementation of the rate, but our standards do not attempt to address the rate issues associated with FERC’s directives. This seems to be no different than the variability of the sale of Firm service.<br><br>3. Rates should not take effect until FERC approval is received, and at least 60 days should be set aside for the FERC to grant approval.<br>Response: The SDT believes there may be some complexity in the implementation of the rate, but our standards do not attempt to address the rate issues associated with FERC’s directives. This seems to be no different than the variability of the sale of Firm service.<br><br>4. Rates should not change within a month (i.e., rates should be applied to all PTP reservations in full month intervals). |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| | | | Response: The SDT believes there may be some complexity in the implementation of the rate, but our standards do not attempt to address the rate issues associated with FERC's directives. This seems to be no different than the variability of the sale of Firm service.<br>5. The tariff defines procedures for studies of firm point-to-point requests (Section 19) and of network integration transmission service requests (Section 32). These procedures are aligned with respect to response and study times, which are outlined below:<br>a. After receiving request for service, TSP has 30 days to tender a System Impact Study (SIS) agreement<br>b. Customer has 15 days execute SIS agreement and return it<br>c. TP has 60 days to complete SIS or, if unable, TSP must contact customer and provide estimated completion date and reason for delay<br>d. If all or part of the service can be accommodated, customer has 15 days to execute service agreement or request that it be filed unexecuted<br>e. If additional upgrades are needed, TSP has 30 days to tender a Facilities Study (FS) agreement<br>f. Customer has 15 days to execute and return the FS agreement<br>g. TP has 60 days to complete FS or, if unable, TSP must contact customer and provide estimated completion date and reason for delay<br>h. Customer provides letter of credit or other security equivalent to the cost of the new facilities or upgrades<br>i. Customer has 30 days to execute a service agreement or request that it be filed unexecuted<br>6. The procedure outlined in #5 is for transmission service, but CBM is a margin and not a transmission service. FERC has not provided a mechanism in the pro-forma tariff to charge customers for CBM and, also, FERC did not establish CBM as a separate service in Order 890. As such, there is no clearly defined mechanism for charging customers for transmission system upgrades specifically set aside for CBM.<br>Response: The SDT has modified the requirement to offer the requester options including studies, but not specifically require a System Impact Study to be offered.<br><br>7. MOD-004-1 establishes 14 days for setting CBM associated with monthly requests (R4.) and 60 days for setting CBM yearly requests (R5.). Requirement R6. establishes a procedure for requesting a system impact study after CBM has been established under Requirements R4. and R5.<br>8. It is impossible to apply the evaluation timing rules for both R4. and R5. whenever a single modification changes both monthly and yearly values (e.g., LSE submits an update that requests increase of the monthly value 3 months from now and also requests increase of the yearly values for all subsequent years).<br>Response: R6 is intended to address this. The standard allows for the initial request to be split into two pieces (shorter-term and longer-term), which can be processed separately (like two requests). R6 then requires notification when each piece has been processed.<br>9. TPs must make rate filings to accommodate Order 890 paragraphs 257 and 263, CBM values must, at some point, be "locked in" prior to the filing.<br>Response: The SDT believes there may be some complexity in the implementation of the rate, but our standards do not attempt to address the rate issues associated with FERC's directives. This |

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| | | | seems to be no different than the variability of the sale of Firm service.<br>10. Rates should not take effect until FERC approval is received, and at least 60 days should be set aside for the FERC to grant approval.<br>Response: The SDT believes there may be some complexity in the implementation of the rate, but our standards do not attempt to address the rate issues associated with FERC's directives. This seems to be no different than the variability of the sale of Firm service.<br><br>11. Rates should not change within a month (i.e., rates should be applied to all PTP reservations in full month intervals).<br>Response: The SDT believes there may be some complexity in the implementation of the rate, but our standards do not attempt to address the rate issues associated with FERC's directives. This seems to be no different than the variability of the sale of Firm service.<br>Recommendations:<br>The following changes are requested so that Transmission Service Providers may meet Order 890 requirement for filing Point-to-Point rates that do not include the cost of the CBM set-aside:<br>1. Monthly requests should be submitted for the current year and the following two years. (NERC)<br>a. This should constitute one request type which is only permitted to use available transmission capability (no upgrades). (NERC)<br>b. Evaluation shall be performed commensurate with reservation response timing rules for monthly firm Point-to-Point requests (NAESB)<br>c. During the evaluation of Monthly CBM requests, CBM requests should be assigned the same reservation priority as yearly firm PTP and designated network service. (NAESB) This will assure that these requests will be evaluated in queue order and will not be superseded by higher priority requests.<br>d. The TSP shall establish in its CBMID rules for queuing of monthly CBM requests in order to accommodate the TP's tariff filing needs (each TSP shall establish when Monthly CBM requests are no longer permitted to change). (NERC)<br>2. Yearly requests should be submitted for the remaining years of the 10 year period.(NERC)<br>a. This constitutes a second request type which is only permitted to use available transmission capability (no upgrades).(NERC)<br>b. Yearly requests shall be updated at least yearly, but may be submitted more frequently. (NERC)<br>c. During the evaluation of Yearly CBM requests, CBM requests should be assigned the same reservation priority as yearly firm PTP and designated network service. (NAESB) This will assure that these requests will be evaluated in queue order and will not be superseded by higher priority requests.<br>d. Evaluation shall be performed commensurate with reservation response timing rules for yearly firm Point-to-Point requests (NAESB)<br>e. The TSP shall establish in its CBMID any rules for queuing of yearly CBM requests in order to accommodate the TP's tariff filing needs (each TSP shall establish when Yearly CBM requests are no longer permitted to change). (NERC)<br>3. At no time shall the Monthly requests overlap the yearly requests. If overlap does occur, the |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| | | | monthly request shall take precedence over the overlapping yearly request. (NERC)<br>4. NERC should remove the last bullet in R6.1 (The option to request a system impact study.). This will streamline the evaluation process and simplify the Standards approval process (and subsequent FERC proceeding). NERC will not be forced to 1) develop a procedure similar to #5 in Duke Observations (above) or 2) defend why the proposed procedure is different.<br><br>Response: The SDT has modified the requirement to offer the requester options including studies, but not specifically require a System Impact Study to be offered. |
| Response: Please see in-line responses. | | | |
| Entergy Services Inc. | | ☑ | |
| EPSA | | | |
| ERCOT | | | |
| Fall River Rural Electric Cooperative, Inc. | | ☑ | |
| FirstEnergy Corp. | | ☑ | |
| Flathead | | ☑ | |
| FRCC | | ☑ | |
| Georgia Transmission Corporation | | ☑ | |
| Hydro One Networks | | | |
| Hydro-Québec TransÉnergie (HQT) | | ☑ | We would like confirmation from the Drafting Team that our interpretation of how the MOD-004 requirements can apply in areas that employ competitive wholesale markets in a manner that does not conflict with approved tariffs. In ISO/RTO markets where resource adequacy is performed by the ISO/RTO (i.e., an independent Balancing Authority), and by virtue of the market, the Transmission Service Provider does not offer transmission service in advance of physical flow, there is no ability for the LSE to 'request' CBM as defined in the standards. However, the reliability need for CBM by the LSE is satisfied by the market rules and associated tariffs. As such, the entities' CBMID would describe how the reliability needs of the LSEs, as relates to securing CBM is met and why there is no need for the LSE to 'request' CBM in the manner described in the standards. We would like confirmation from the Drafting Team that documentation of CBMID in this manner – i.e., through specifying that an LSE need not "request" any particular transmission service – would satisfy the reliability requirements of MOD-004. LSE, and CBMID should be defined in the Background Information on p. 3. |
| Response: The SDT believes it has modified the standard in a way that meets your needs. The SDT expects that a market such as you describe would have a CBMID that describes that LSEs have designated the Market Operator to act on their behalf. When LSEs were asked to show compliance, the SDT believes they could reference the CBMID as well. As long as the timeframes described in the standard are met, | | | |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| compliance should not be problematic. Note that the SDT has modified the standard such that if you do not use CBM, you do not have to offer it, which may also address your concerns. | | | |
| IESO | ☑ | | Selling transmission service is not really a reliability issue. It is a commercial issue. Additionally, FERC is very clear in its 693 Order that the primary purpose of ordering these changes to the reliability standards is to create transparency, eliminate undue discrimination, and ensure consistency. If existing standards were contributing to these problems, ordering these changes would be appropriate. However, using the reliability standards to effect these goals is an inappropriate use. Do we want to say anything like that here or let it go? |
| Response: These standards do not address the selling of transmission service. Rather, they address the issue of identifying the amount of capability available on the system in a consistent way such that all Transmission Service Providers have a more accurate understanding of whether or not expected use of the transmission system (their own and their neighbors) is going to result in a reliability concern. While the SDT anticipates that this more accurate information will have an impact on the sale of service, the issues of transparency and discrimination to be addressed by NAESB. | | | |
| ISO/RTO Council (IRC) | ☑ | | MOD-030<br>Selling transmission service is not a reliability issue. It is a commercial issue. Additionally, FERC is very clear in its 693 Order that the primary purpose of ordering these changes to the reliability standards is to create transparency, eliminate undue discrimination, and ensure consistency. If existing standards were contributing to these problems, ordering these changes would be appropriate. However, using the reliability standards to effect these goals is an inappropriate use because they do not affect reliability. |
| Response: These standards do not address the selling of transmission service. Rather, they address the issue of identifying the amount of capability available on the system in a consistent way such that all Transmission Service Providers have a more accurate understanding of whether or not expected use of the transmission system (their own and their neighbors) is going to result in a reliability concern. While the SDT anticipates that this more accurate information will have an impact on the sale of service, the issues of transparency and discrimination to be addressed by NAESB. | | | |
| Manitoba Hydro | | ☑ | |
| MidAmerican Energy Electric Trading | ☑ | | Standard MOD-001-1 Requirement R1, footnote 1<br><br>A primary intent of these related standards to is promote consistency among Transmission Service Providers in the calculation of ATC. This goal of consistency is violated by the provisions of footnote 1, which would permit a single Transmission Service Provider to use different methodologies on the same Posted Path at different points in time. MidAmerican also feels that there is absolutely no way each of the three methodologies would yield consistent and equivalent results.<br><br>While we acknowledge that Order No. 693 found that it is "not necessary to require a single industry-wide ATC calculation methodology" (Order No. 693, Paragraph 1030), the Commission's intent was that ATC be calculated in a manner that "provides predictable and sufficiently accurate, consistent, equivalent, and replicable ATC calculations regardless of the methodology used by the region" (Order No. 693, Paragraph 1034). Only under unusual conditions would there be a reason for a single Transmission Service Provider to use differing ATC methodologies on different Posted Paths, and only rarely would there be a reason to use different methods on the same Posted Path at different points in time. Permitting these deviations would make it essentially impossible to verify the calculations of |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| | | | the Transmission Service Provider, because it would be difficult to determine what methodology was in effect on which Posted Path at which point in time. In addition, these deviations would permit manipulation of ATC calculations. |
| Response: Entities are required to disclose in the ATCID “Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC calculations can be validated.” The SDT believes this requirement will address your concern, and require the provider to make clear what methodologies are used at which times. | | | |
| Midwest ISO | | ☑ | |
| Modesto Irrigation District | | ☑ | MID supports the comments submitted by SMUD on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry. |
| Response: Please see the WECC MIC MIS ATC Drafting Team response. | | | |
| MRO | | ☑ | |
| New Brunswick System Operator | | ☑ | |
| NorthWestern Energy (NWMT) | ☑ | | Throughout, these standards assert that the calculation of ATC is a reliability matter. This is incorrect. ATC is a commercial product, a commodity that is offered by transmission service providers, sold to transmission customers, and sometimes traded amongst transmission customers. FERC requires jurisdictional transmission providers to calculate and post ATC. 18 CFR Part 37.6 contains the standards of ATC calculation and posting. It is not reasonable to be subject both to FERC enforcement of the CFRs and to NERC enforcement of these overlapping standards.<br><br>In the west, reliability is not impacted by the miscalculation, posting, or sale of ATC. It is when transactions are scheduled that reliability is potentially impacted. Improper TTCs impact reliability. Failure to evaluate proposed transactions and their impacts to the transmission system impact reliability. It is reasonable that NERC reliability standards cover the calculation of TTC, and some aspects of CBM and TRM. |
| Response: These standards do not address the posting of ATC. They also provide significant more detail than the CFR with regard to the requirements related to calculation of ATC. The drafting team does not believe there is overlap.<br><br>The SDT agrees that failure to evaluate proposed transactions and their impacts to the transmission system impact reliability, and therefore require that, through these standards, all Transmission Service Providers have an accurate understanding of how both proposed transactions and those to which the Transmission Service Provider has already committed will affect the transmission system. | | | |
| NPCC Regional Standards Committee | | ☑ | We would like confirmation from the Drafting Team that our interpretation of how the MOD-004 requirements can apply in areas that employ competitive wholesale markets in a manner that does not conflict with approved tariffs. In ISO/RTO markets where resource adequacy is performed by the ISO/RTO (i.e., an independent Balancing Authority), and by virtue of the market, the Transmission Service Provider does not offer transmission service in advance of physical flow, there is no ability for the LSE to 'request' CBM as defined in the standards. However, the reliability need for CBM by the LSE is satisfied by the market rules and associated tariffs. As such, the entities' CBMID would |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| | | | describe how the reliability needs of the LSEs, as relates to securing CBM is met and why there is no need for the LSE to 'request' CBM in the manner described in the standards. We would like confirmation from the Drafting Team that documentation of CBMID in this manner – i.e., through specifying that an LSE need not "request" any particular transmission service – would satisfy the reliability requirements of MOD-004. LSE, and CBMID should be defined in the Background Information on p. 3. |
| Response: The SDT believes it has modified the standard in a way that meets your needs. The SDT expects that a market such as you describe would have a CBMID that describes that LSEs have designated the Market Operator to act on their behalf. When LSEs were asked to show compliance, the SDT believes they could reference the CBMID as well. As long as the timeframes described in the standard are met, compliance should not be problematic. Note that the SDT has modified the standard such that if you do not use CBM, you do not have to offer it, which may also address your concerns. | | | |
| NYISO | | ☑ | The NYISO joins in, and supports, the comments submitted by the IRC in response to this question. The NYISO also supports the comments submitted by the NPCC.<br><br>Except as noted by the IRC and NPCC, the NYISO does not believe that there will be any conflict between the proposed ATC standards and anything in the NYISO's tariffs, the NYISO market design, or any FERC order related to them, provided that NERC interprets the standards with reasonable flexibility. So long as NERC takes this kind of approach, the NYISO expects to be able to apply its chosen NERC-approved ATC calculation methodology consistent with its use of a FERC-approved financial reservation transmission service model. The NYISO believes that NERC can interpret the standards with reasonable flexibility without reducing their technical accuracy or diminishing their effectiveness. Transmission providers that offer financial reservation transmission service would still be required to comply with all standards to the extent that they are applicable, exactly like transmission providers that offer physical reservation service.<br><br>By way of background, under the NYISO's financial reservation model, customers schedule transmission service "implicitly" when they submit energy schedules via the spot markets or arrange for bilateral transactions. There are no express reservations of physical transmission service and customers may schedule transactions between any two points, so long as doing so is not inconsistent with a security-constrained economic dispatch. All desired uses of the grid are scheduled to the extent that customers are willing to pay congestion charges, which can be hedged using financial rights. Stated differently, customers' ability to schedule transactions within New York is not limited by a pre-defined amount of ATC. Instead, the entire capacity of the New York State Transmission System is made available for both firm and non-firm service prior to the start of each market cycle. ATC is calculated and posted based on the transactions accepted in the day-ahead and real-time market. Consequently, the information conveyed by the NYISO's ATC postings is different than what is conveyed under physical reservation systems. As FERC has recognized, the NYISO's postings are really advisory "projections", albeit advisory projections that the Commission believes can be useful to customers.<br><br>Nothing in Order No. 890 required the NYISO to modify this system, no New York stakeholder has asked that it be changed, and there is no reason why it cannot be accommodated within a framework of rigorous and technically accurate ATC standards. NERC should not interpret the ATC standards in |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| | | | a way that would require the NYISO to perform functions that are inconsistent with its model or with past waivers it has received from FERC's OASIS/ATC regulations and related NAESB business practices. The NYISO identifies a limited number of requirements where this issue could arise in its response to Question Six, below. The NYISO believes that its ATC practices will comply with NERC's proposed requirements and that any differences between the details of its procedures and those of other transmission providers can be addressed in its ATCID.<br><br>For NERC's reference, the orders granting the NYISO waivers from various FERC OASIS and ATC requirements, and from related NAESB business practices, include New York Independent System Operator, Inc. 121 FERC 61,036 (2007); New York Independent System Operator, Inc., 117 FERC ¶ 61,197 (2006); New York Independent System Operator, Inc., 94 FERC ¶ 61,215 (2001); and Central Hudson Gas & Electric Corp., et al., 88 FERC ¶ 61,253 at 61,803 (1999). |
| Response: These standards do not address the selling of service, and instead only apply to the determination of ATC. | | | |
| PacifiCorp | | ☑ | |
| PJM Interconnection LLC | ☑ | | The requirements are procedural in nature and conflict with PJM's implementation of ATC and CBM. The LSEs have delegated authority to implement CBM and determine reserve margins to PJM in the RAA. The PJM membership has enjoyed the benefits of an area wide application of CBM. The standards specify requirements that do not observe differing implementations of CBM. The procedural requirements of the standards conflict with the procedures in PJM Manuals and implemented by PJM In the RAA, and JOAs. These standards additionally would then affect the ability for LSEs to delegate responsibility to ISOs by limiting both the general flexibility by which CBM may be implemented and the specific application in PJM.<br><br>The standards must state that the requirements do not apply in the event that the responsible parties have FERC approved agreements in place that differ in implementation. Such agreements may include the RAA, and JOAs between ISOs. |
| Response: The standard has been modified to include Planned Resource Sharing Groups, which should address your concerns.<br>The SDT is uncertain with the manner in which the standards conflict with PJM's implementation of ATC, as no detail has been provided. Please also see the responses to your other comments.<br>Paragraph 160 of Order 890 provides ISOs and RTOs the means through which they can request to be exempted from the requirements of the Order, and NERC has similar provisions through which exemptions from the requirements of this standard may be pursued. | | | |
| Progress Energy, Carolinas | | | |
| Public Service Commission of SC | | ☑ | |
| Public Utility District #2 of Grant County, Washington | | ☑ | |
| Puget Sound Energy | ☑ | | Throughout, these standards assert that the calculation of ATC is a reliability matter. This is incorrect. ATC is a commercial product, a commodity that is offered by transmission service providers, sold to transmission customers, and sometimes traded amongst transmission customers. |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| | | | FERC requires jurisdictional transmission providers to calculate and post ATC. 18 CFR Part 37.6 contains the standards of ATC calculation and posting. It is not reasonable to be subject both to FERC enforcement of the CFRs and to NERC enforcement of these overlapping standards.<br><br>In the west, reliability is not impacted by the miscalculation, posting, or sale of ATC. Reliability is impacted when transactions are scheduled in a manner that causes flows to exceed a path's TTC. And ,as such, improper TTCs impact reliability. Failure to evaluate proposed transactions and their impacts to the transmission system impacts reliability. It is reasonable that NERC reliability standards cover the calculation of TTC, and some aspects of CBM and TRM. |
| Response: These standards do not address the posting of ATC. They also provide significant more detail than the CFR with regard to the requirements related to calculation of ATC. The drafting team does not believe there is overlap.<br><br>The SDT agrees that failure to evaluate proposed transactions and their impacts to the transmission system impact reliability, and therefore require that, through these standards, all Transmission Service Providers have an accurate understanding of how both proposed transactions and those to which the Transmission Service Provider has already committed will affect the transmission system. | | | |
| Salmon River Electric Cooperative | | ☑ | |
| Salt River Project | ☑ | | See Answer to question Q2 |
| Response: Please see response to question Q2. | | | |
| Santee Cooper | | ☑ | |
| SERC ATCWG | | ☑ | |
| Sierra Pacific Resources Transmission | ☑ | | Throughout, these standards assert that the calculation of ATC is a reliability matter. This is incorrect. ATC is a commercial product, a commodity that is offered by transmission service providers, sold to transmission customers, and sometimes traded amongst transmission customers. FERC requires jurisdictional transmission providers to calculate and post ATC. 18 CFR Part 37.6 contains the standards of ATC calculation and posting. It is not reasonable to be subject both to FERC enforcement of the CFRs and to NERC enforcement of these overlapping standards. |
| Response: These standards do not address the posting of ATC. They also provide significant more detail than the CFR with regard to the requirements related to calculation of ATC. The drafting team does not believe there is overlap.<br><br>The SDT agrees that failure to evaluate proposed transactions and their impacts to the transmission system impact reliability, and therefore require that, through these standards, all Transmission Service Providers have an accurate understanding of how both proposed transactions and those to which the Transmission Service Provider has already committed will affect the transmission system. | | | |
| Snohomish PUD | ☑ | | Throughout, these standards assert that the calculation of ATC is a reliability matter. This is incorrect. ATC is a commercial product, a commodity that is offered by transmission service providers, sold to transmission customers, and sometimes traded amongst transmission customers. FERC requires jurisdictional transmission providers to calculate and post ATC. 18 CFR Part 37.6 contains the standards of ATC calculation and posting. It is not reasonable to be subject both to |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| | | | FERC enforcement of the CFRs and to NERC enforcement of these overlapping standards.<br><br>In the West, reliability is not impacted by the miscalculation, posting, or sale of ATC. It is when transactions are scheduled that reliability is potentially impacted. Improper TTCs impact reliability. Failure to evaluate proposed transactions and their impacts to the transmission system impact reliability. It is reasonable that NERC reliability standards cover the calculation of TTC, and some aspects of CBM and TRM. |
| Response: These standards do not address the posting of ATC. They also provide significant more detail than the CFR with regard to the requirements related to calculation of ATC. The drafting team does not believe there is overlap.<br><br>The SDT agrees that failure to evaluate proposed transactions and their impacts to the transmission system impact reliability, and therefore require that, through these standards, all Transmission Service Providers have an accurate understanding of how both proposed transactions and those to which the Transmission Service Provider has already committed will affect the transmission system. | | | |
| The Southeast Coalition | ☑ | | Please see list below.<br><br>Consistency Between ATC calculations and Operational & Long-Term Expansion Studies:<br>MOD-001 (R8). Requirement 8 of MOD-001 does not fully include the goals and requirements established in FERC Order 890/Cite 292 & 237 which are very clear about requiring TSPs to use data and modeling assumptions for ATC calculations that are consistent with those used in operations planning and long-term system expansion studies. FERC clearly states its expectation in the following extract of Order 890/Cite 292: "We find that requiring consistency in the data and modeling assumptions used for ATC calculations will remedy the potential for undue discrimination by eliminating discretion and ensuring comparability in the manner in which a transmission provider operates and plans its system to serve native load and the manner in which it calculates ATC for service to third parties". Furthermore, FERC establishes the following requirement in Citation 237 of Order 890: "We direct public utilities, working through NERC, to address, through the reliability standards process, any differences in developing TTC/TFC for transmission provided under the pro forma OATT and for transfer capability for native load and reliability assessment studies"<br>It is known that some Transmission Providers use a number of procedures such as: switching operating guides, generation re-dispatch, dropping load, etc. to mitigate transmission limit violations when performing reliability assessments of their systems in the planning horizon. Based on the application of mitigation procedures, these TSPs conclude that their transmission systems are reliable and thus, no transmission upgrades/reinforcements are needed. However, these mitigation procedures are not made available to third parties requesting transmission service and, as a result of this, transmission service requests are refused or the requestor is assigned financial responsibility for upgrading constrained facilities which could be mitigated by the application of the TSP operating procedures. Furthermore, these mitigation procedures typically are not included in the ATC models, which leads to artificial overloads, negative ATC/AFC, and the unduly discriminatory denial of transmission service.<br>We believe that requirement 8 of MOD-001 should fully incorporate the FERC directive in Order 890/Cite 292 & 237 and explicitly require TSPs to incorporate ALL data, modeling assumptions, and mitigation procedures used in operations planning and long-term expansion studies in their ATC/AFC |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| | | | models and calculations. A measurement to ensure full compliance with this requirement should be added to the Standard.<br>Response: The drafting team believes that R8 (currently R6) does capture the intent of the FERC statements cited. For clarity a partial list of assumptions has been included in the measure, M6.<br><br>Over-Generation:<br>Order 890 at Cite 245 clearly establishes the requirement by which reservations from a generator in excess of the generator's nameplate capacity should not be simultaneously included in the calculation of ETC. Furthermore, FERC directed NERC to develop requirements in MOD-001 that lay out clear instructions on how to model a generator, which has reservations in excess of its nameplate capacity for a given time frame, to prevent unrealistic utilization of transmission capacity associated with over-generation. MOD-001 does not include the requirements directed by FERC to ensure that over-generation does not occur in the calculation of ETC.<br><br>Response: The drafting team has discussed this requirement in detail, and can find no clear-cut practice that will not either 1.) harm open access by denying service, or 2.) harm reliability by ignoring the impact of potential schedules. The drafting team believes that over time, additional SARs and directives will arise that call for continued improvement. The SDT encourages the commenters to submit such SARs as they feel appropriate to address their concerns, and provide explicit guidance as to what language would be appropriate to accomplish those goals.<br><br>ATC/AFC Coordination:<br>Requirement 10 of MOD-001 identifies the data set to be made available by Transmission Service Providers for ATC/AFC coordination purposes. Requirement 10 also establishes that this data needs to be made available by a TSP if there is a request by another TSP, Planning Coordinator, Reliability Coordinator, or Transmission Operator. Requirement 10 does not require the data set be exchanged by TSPs or the use of the data for coordination purposes. Thus, this requirement is inconsistent with Order 890 at Cite 310 wherein FERC directed TSPs to coordinate ATC/AFC and, as part of this directive, requires the establishment of a standard data exchange mechanism to enable the coordination process. Cite 310 of Order 890 states the following: "the Commission adopts the NOPR proposal and directs public utilities, working through NERC, to revise the related MOD reliability standards to require the exchange of data and coordination among transmission providers…". Furthermore, FERC in the last sentence of Cite 310 makes it clear that "As explained above, transmission providers are required to coordinate the calculation of TTC/TFC and ATC/AFC with others and this requires a standard means of exchanging data".<br>Therefore, it is clear to us that FERC's ultimate objective is the on-going coordination of TTC/TFC and ATC/AFC by transmission providers. To achieve this objective, requirement 10 of MOD-001 should be changed to mandate data exchange and on-going coordination of TTC/TFC and ATC/AFC among adjacent Transmission Service Providers.<br>Response: The standards address this by requiring the provision of the data in MOD-001 and the use of the provided data in the individual MOD-028 and MOD-030 standards. Since the Rated System Path methodology (MOD-029) does not use simulations in the same fashion as in the other two |

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| | | | methodologies, it does not require the data be used to the same degree, but does incorporate some of the provided data in R1.<br><br>Benchmarking of ATC Models:<br>Order 890 at Cite 290 & 291 requires NERC to modify ATC-related standards to incorporate requirements for the periodic review, update, and benchmark of models used for ATC calculations. FERC states the following in Cite 290: “this [requirement] means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers”.<br>This cornerstone of Order 890, the accuracy of ATC calculations through review, updating, and benchmarking to actual events, has not been included in the ATC standard. Even if these requirements have been included in other reliability standards associated with ATC calculations, there should be a clear reference to these requirements in the ATC standard. Enforcing the above requirements - to review, update, and benchmark models used in ATC calculations - is essential to instill confidence in the market place and to obtain accurate and realistic ATC values.<br>Response: NERC intends to address these requirements with future standards development efforts.<br><br>Transparency:<br>Throughout Order 890, FERC has included various requirements to increase transparency in ATC calculations. In the spirit of Order 890 Cite 210 & 471 requirements, TSPs should be required to post all non-confidential input data & power flow models necessary to replicate their ATC calculations & results. If a data item used in ATC calculations is considered to be confidential, this data item should be identified as such and accordingly, documented in the TSP ATCID. Order 890 Cite 323 requires TSPs to document modeling assumptions, parameters, and methodologies used in their ATC calculations, and to make this documentation available along with work papers and analyses necessary to justify settings of ATC parameters.<br>We believe that requiring TSPs to post a comprehensive set of ATC input data, models, and documentation of their methodologies, is not only necessary to provide the transparency required by Order 890, but will enable market participants, transmission customers and regulators, to validate ATC calculations and use the models in their own analyses. This will increase confidence in ATC calculations, provide meaningful transparency, and significantly improve the overall ATC process. Further, the general posting requirements to meet Order 890 transparency requirements should be included in MOD-001 and the posting details should be included in the business practices currently being developed by NAESB.<br>It is important to note that, currently, there are TSPs who post a great deal of ATC input data and power flow models. It is commendable that these TSPs have taken great strides in providing transparency. It is now time for other TSPs to follow suit.<br><br>Response: NAESB will be addressing all posting, transparency, and disclosure requirements other than those related to reliability coordination. |

| Commenter | Yes | No | 5. Comments on Conflicts |
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| | | | Consistency of Modeling Practices:<br>Although MOD-001 states that its purpose is to promote “consistent application of ATC calculations” (as required by Order 890), this standard does not explicitly require consistent modeling practices to calculate ATC values for different time frames. It is known that some TSPs use different transmission models and modeling practices when calculating ATC values for different time frames. For example, the dispatch model used in the calculation of daily ATC values may be different than the dispatch model used in monthly ATC calculations. Another example is the representation of external systems in ATC models used for daily vs. monthly ATC calculations. These inconsistent modeling practices lead to inconsistent ATC values and reduced confidence in ATC calculations.<br>TSPs should be required to eliminate or minimize inconsistent modeling practices. If inconsistent modeling practices can not be eliminated, TSPs should identify and document differences in models and modeling practices due to ATC calculation time frames and provide justification for them.<br><br>Response: The standard does require models be developed in a standard way. It also require disclosure of the procedures in the ATCID, and that assumptions be consistent with those used in operations and planning standards. The SDT believes that this has set an appropriate level of consistency at this time. In order to have accurate ATC calculation, the SDT believes that having different models for different time periods is acceptable. |
| Response: Please see in-line responses. | | | |
| Southern Company Transmission | | ☑ | |
| SPP | | | No comment. |
| Tacoma Power | | ☑ | |
| Tri-State Generation and Transmission Association | | ☑ | |
| WECC MIC MIS ATC TF Drafting Team | | ☑ | |
| WestConnect Transfer Capability Workgroup | | ☑ | |
| Western Area Power Administration - RMR | | ☑ | |

**6. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standards.**

**Summary Consideration:** May commenters elected to provide comments in this section, rather than in the specific question areas. In this cases, responses are consistent with those provide in earlier questions.

Some entities expressed confusion with regard to the difference between NERC and NAESB responsibilities. The SDT clarified that items related to the customer interface, such as the posting of documents on OASIS or public disclosure of information to the marketplace, were the responsibility of NAESB. Items related to the determination of information related to reliability coordination are within the scope of NERC.

Several entities expressed concern regarding the requirement that CBM be granted prior to TSRs when capacity became available. The drafting team discussed this issue at length, and determined that both methods (holding capacity for un-granted CBM requests, putting CBM requests into a queue for processing) were acceptable. Accordingly the SDT has changed the standard to allow entities to take either approach, provided they document the manner used in their ATCID.

Some entities expressed a desire to have the TSP set the SCM to the maximum amount requested, rather than the sum. The SDT explained the choice of this course of action because of potential conflicts with state or local regulations.

Some entities questioned the need for NERC to require data provision and exchange if FERC or NAESB is already doing so. The SDT explained that these standards required the provision and exchange of data for reliability reasons, which need to persist regardless of the status of FERC or NAESB requirements.

Many entities expressed concern that the monthly updates related to changes in CBM were excessive. The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. The standard has been modified to clarify that entities must update their CBM at least once a month if it changes, but that determination may be through a recalculation or through a simple adjustment (e.g., a addition or subtraction, based on contracts or other drivers).

Many entities expressed concerns with the implication that MOD-030 would require entities to convert all Flowgate Capabilities into path Transfer Capabilities for posting. The standard was modified to state that entities were required to use the provided formula to calculate ATCs and TTCs if they were doing such a conversion, but that the standards did not actually require the conversion unless entities were compelled to do so for another reason. To the extent entities wished to use a tool to do the conversion, the standard allows for this.

Some market operators requested clarification that the standards were not forcing any particular market design. The SDT agreed and clarified this, and in some cases provided examples how a market operator and its customers would comply with the standards.

With regard to the Violation Risk Factors, several entities requested either many or all requirements be set to Low. The drafting team discussed the requested changes at length, but was ultimately unable to come to consensus sufficient enough to establish the required supermajority vote to change the VRFs. NERC defines that requirement with a Violation Risk Factor of Lower is one that "if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system." The SDT does believe that there are many requirements in these standards to which this VRF should apply, but there also are many that can have a more significant impact than this.

The drafting team modified the approach to counterflow in the standards based on the comments provided. The default values were removed and a requirement for the ATCID to provide detail regarding how the TSP handles counterflows.

Many entities expressed confusion with regard to the difference between NERC and NAESB responsibilities. The SDT clarified that items related to the customer interface, such as the posting of documents on OASIS or public disclosure of information to the marketplace, were the responsibility of NAESB. Items related to the determination of information related to reliability coordination are within the scope of NERC.

Many entities provided supportive comments, indicating particular areas of the standards they felt were accurate representations of industry need.

The SDT made other minor corrections and clarifications as needed.

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| Alberta Electric System Operator | The AESO currently does not use OASIS for transmission services but is sharing information with the British Columbia Transmission Corporation for posting transmission services on the only one shared tie line. To meet some of the requirements in these standards that require the entity to post transmission information (such as ATCID) on OASIS, would it be acceptable for such entity to post the information on its website instead? Could this provision be added to the requirements? |
| Response: These standards are not addressing posting requirements. While these standards require the existence of certain data or documents, NAESB will be addressing the posting of them. | |
| Ameren Services | MOD-004-1<br>6. Effective Date: "all six standards are approved" MOD-001-1 lists the six standards, should list here as well.<br>Response: The SDT has modified the language such that the standards are consistent, recognizing that the standards will now be posted for separate ballots.<br>.1.2.2. "each impacts" => "each impact"<br>Response: The SDT has corrected this typographical error. |
| Response: Please see in-line responses. | |
| American Transmission Company | MOD-001-1 – Available Transfer Capability<br><br>R1: Potential source of problems – the Transmission Operator (American Transmission Co.) selects an ATC methodology that the Transmission Service Provider (Midwest Independent System Operator) must use for calculations even if it is not equipped to use the methodology chosen. May want to add language that urges agreement between TO and TSP.<br>Response: The drafting team discussed this, and felt it could not create such a requirement. If the parties did not agree, it would be difficult to determine who was at fault and therefore exposed to sanctions.<br><br>MOD-004-1 – Capacity Benefit Margin<br>R2: Typo in line two, “CBID” should be “CBMID”<br>Response: The SDT has corrected this typographical error.<br><br>R4.1.2.2: Should be rewritten. Suggestion: “Impacts with a Distribution Factor of 3% or greater relative to OTDF |

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| | Flowgates and 5% or greater relative to PTDF Flowgates will be classified as significant."<br>Response: This requirement has been removed from the standard.<br><br>R4.2: CBM should not be based on the sum of all requests – we don't need to plan for a simultaneous capacity emergency in every area impacted by a Flowgate. Rather, CBM should be based on the maximum of all requests. By reserving the maximum CBM of all requests, a single capacity emergency in any one area impacted by the Flowgate will be covered.<br>Response: The SDT has written the standard with the intention of allowing LSEs to aggregate requests in order to address the scenario you describe. The SDT did not want to give the TSP the responsibility to aggregate such requests, as it may result in them creating situations where they unintentionally cause the LSE to violate regulatory requirements for resource adequacy.<br><br>R4.2.2: Setting CBM to the lesser of the GCIR impacts or the firm AFC for a Flowgate is not correct, because setting CBM based on AFC or ATC is an invalid circular argument. Consider the following simple example:<br><br>The definition of AFC:TFC – EFC – CBM –TRM + Postbacks + Counterflows = AFC<br>So, if the rating on a Flowgate is 100 MW (TTC = 100),<br>there are no existing transmission commitments (ETC = 0),<br>the calculated GCIR impacts is 25 MW (CBM = 25),<br>and for the sake of this example there is no Transmission Reliability Margin (TRM = 0),<br>and no Postbacks or Counterflows.<br><br>Our AFC: 100 – 0 – 25 – 0 + 0 + 0 = 75<br><br>Now assume that firm sales account for 75 MW of flow across the Flowgate, so ETC = 75.<br><br>New AFC: 100 – 75 – 25 – 0 + 0 + 0 = 0<br><br>So in this case, we've got an AFC of zero, which is less than the calculated GCIR, so we would set CBM to zero even though we previously set aside 25MW for CBM that is being unused!<br><br>CBM should be set to the calculated maximum GCIR value for the impacted LSE's. As CBM fluctuates up and down year-by-year the AFC will be affected and may sometimes go negative, but this is a necessary by-product of selling transmission service (ETC) far into the future.<br>Response: The SDT has modified the standard such that it allows the Transmission Service provider to choose the manner in which they will handle CBM requests that exceed available capacity. The standard also requires a |

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| | description of that choice to be included in the CBMID.<br><br>R4.3: CBM should not be reduced based on insufficient capacity. If AFC/ATC happens to be negative when a request to use CBM is issued, the CBM transactions should be granted and then all transactions across the constrained element, including the CBM transactions, should be curtailed on a pro-rata basis, which will result in load shedding procedures for the capacity deficient entity. This is the next step in an Energy Emergency Alert. CBM is the last attempt in EEA2 to prevent EEA3 and firm load curtailment.<br>Response: The SDT has modified the standard such that it allows the Transmission Service provider to choose the manner in which they will handle CBM requests that exceed available capacity. The standard also requires a description of that choice to be included in the CBMID. The standard is not intended to address the load shedding process.<br><br>R5.2: Change sum to maximum, see note for R4.2.<br>The SDT chose this course of action because of potential conflicts with state or local regulations. If a state mandates that entity X rely on 200MW worth of external resources for generation adequacy, and mandates entity Y rely on 200MW as well, these two entities may make separate requests to the TSP, each requesting 200MW. If the TSP only grants 200MW of CBM, and a capacity emergency occurs that impacts both entities, then there will not be enough CBM. Rather than put the TSP and LSEs in this position, the standard requires the TSP grant what he is asked for, and gives LSEs the opportunity to make joint requests, directly or through a third party, so that aggregations such as you describe can occur – but only with the LSEs knowledge and consent. The drafting team has modified the language to explicitly allow planned resource sharing groups to address your concern.<br><br>MOD-008-1 – Transmission Reliability Margin<br>R1.5: Typo in line one, change “all” to “any.”<br>Response: The SDT has modified this language to read “If TRM is not used, a statement of that practice.”<br><br>R4: Shouldn’t the Transmission Operator also have the right to request this information? This requirement only allows other TSP’s to receive the TRM calculation info.<br>Response: The SDT has incorporated the suggested change.<br><br>MOD-030-1 – Flowgate Methodology<br>R2.1: Typo in line one, change “used” to “use.”<br>Response: The SDT has corrected this typographical error.<br><br>R3: Change “Transmission Operator” to “Transmission Service Provider” because MOD-001 requires the TSP to calculate ATC/AFC values.<br>Response: The SDT has incorporated the suggested change. |

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| | R8: Typo in counterflows section, change "ATC" to "AFC"<br>Response: The SDT has corrected this typographical error.<br><br>R9: Typo, "ATCNF" should be "AFCNF"<br>Response: The SDT has corrected this typographical error. |
| Response: Please see in-line responses. | |
| Avista Corporation | MOD-001-1, A., 3. the stated purpose contains goals that are not required for reliable system operation, but rather are for viable commercial activity. Reliable system operations are impacted by incorrect TTC values and uncoordinated transaction scheduling activities.<br><br>Response: The Drafting Team has clarified in the stated purpose why these standards are required for reliable system operation as follows: To promote the consistent and reliable application and documentation of Available Transfer Capability (ATC) calculations for analysis and system operations.<br><br>MOD-001-1, A., 4. Applicability, Transmission Service Providers calculate ATC. Transmission Operators (in the near term) and Transmission Planners (in the longer term) calculate TTC.<br>Response: The SDT agrees that these are good descriptions of the roles entities play in determining ATC and TTC. The SDT does not believe the Transmission Planner should be a applicable entity in the standard, as they are dealing with long-term issues.<br><br>MOD-001-1, B., R1, Transmission Operators calculate transfer capability (TTC) of facilities within their TO areas. Transmission Planners calculate transfer capability (TTC) of facilities within their TP areas. Transmission Service Providers calculate ATC for those paths that they are required to, choose to, or are asked to post.<br>Response: It is unclear what change is being suggested.<br>MOD-001-1, B., R3 Transmission Service Providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability. This requirement to create a separate document creates an undue burden on the industry - transmission customers will have two different documents to review, and transmission service providers will have two different documents to maintain.<br>Response: The standard does not preclude entities from creating one document that meets both needs.<br>MOD-001-1, B., R3.3 the term "Facility" should say "Posted Path" (but see the comment above regarding definition of "Posted Path"). The term facility in the NERC glossary says facility is "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)."<br>Response: The SDT has modified 3.3 and eliminated the language referring to "Facilities."<br>MOD-001-1, B., R3.6 "Allocation methodologies" – it is not clear to what this means? Perhaps the following: "For paths where multiple Transmission Service Providers share capacity or have rights, describe how the capacity is allocated among providers," or words to that effect. |

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| | Response: The Drafting Team added detail to this requirement to address this concern.<br><br>MOD-001-1, B., R4 is not needed, it is already covered in R3.2.<br>MOD-001-1, B., R5 is not needed, it is already covered in R3.2.<br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>MOD-001-1, B., R6 is not necessary. Revisions to Attachment C are to be filed and posted.<br>Response: These are to be notifications to the entities to alert them to changes that may impact them. Filing and posting does not provide notification.<br><br>MOD-001-1, B., R7 Attachment C is already required to be posted (available) for any entity to review, subject to CEII concerns.<br>Response: This requirement is not in conflict with the requirement to post Attachment C.<br><br>MOD-001-1, B., R9 is not a reliability concern. In addition, it is unduly burdensome. Current and accurate ATCs are a commercial concern. In addition, performing 168 hourly calculations every hour when neither TTC nor ETC has changed, benefits no one and is costly. The commercial requirement should be to require the recalculation of hourly ATC once a day and whenever either TTC or ETC changes for any period of time between this hour and the next 168 hours.<br>Response: The SDT has modified the language to not require recalculations if the components in the ATC equation have not changed. However, the SDT does not agree this is only a commercial requirement. The amount of service sold is based on the amount of energy that can be transferred reliably, and these standards intend to ensure that number is as accurate as possible.<br><br>MOD-001-1, B., R10, this requirement for data sharing between reliability entities is a good concept. However, as currently worded, all the burden to supply data is incorrectly placed totally upon the TSP and not on the Transmission Operator or Transmission Planner. Much of the data listed is critical for proper TTC calculation which the TSP may not have access to. The TSP calculates ATC based on upon TTC supplied by the Transmission Operator and/or Transmission Planner.<br>Response: The Transmission Provider will be responsible for working with their Transmission Operators or Transmission Planners to secure the data. |

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| | This requirement does not specify how the request is made or how the response or provision of data is dated.<br>Response: The SDT believes this to be implementation details to be determined by the Transmission Service Provider and the requestor. NAESB may elect to define standards in this area.<br><br>The corresponding measurement, M9, implies that all data items requested will be supplied within 14 days, but requirement states that the TSP will begin to make available at the 14 day mark.<br>Response: M9 measures whether or not the “requested data items” were begun to be made available. By “begun,” the standard means that the process of sending all the data was started, not that only some of the data requested was sent.<br><br>In addition, change first sentence words “…days of a request of any Transmission…” to “…days of a request made by any Transmission…” to read more in-line with the intent.<br>Response: The SDT has rewritten this requirement to be clearer.<br><br>MOD-004-1, A., Capacity Benefit Margin is a use of the transmission system that is requested by a load serving entity. This standard contains requirements for the interactions between the LSE and the transmission provider. These requirements are largely commercial in nature and should be under NAESB development. Reliability standards concerning CBM should only require LSEs to acquire minimum CBM to ensure service to load.<br>Response: CBM is a margin used to ensure reliability. Not only requests for it, but the actual setting of it and its ultimate inclusion in the ATC calculation all have reliability impacts, and are appropriate for development in this standard.<br><br>MOD-004-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider’s CBM methodology. This requirement to create a separate document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and providers would have to maintain two different documents.<br>Response: The standard does not preclude a Transmission Service Provide from using one document to meet both requirements. Note that the Attachment C may not be as detailed as the implementation documents, however.<br><br>MOD-004-1, B., R2 is not necessary. Revisions to Attachment C are to be filed and posted (available) for any entity to review, subject to CEII concerns.<br>Response: R2 is intended to ensure this information is provided to reliability entities for reliability purposes, regardless of what other information is required to be posted to meet FERC requirements.<br><br>MOD-004-1, B., combine R3.3 language into R3.1.<br>Response: The SDT does not understand the reason to combine these requirements. |

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| | MOD-004-1, B., R3.2 it seems more reasonable for the requirement to read “LSE shall review any active CBM requests at least every six months and submit updates as required.”<br>Response: The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. The Standard is requiring that entities update their CBM at least once a month to ensure that no unneeded CBM is still being held back from the market. The standard has been modified to clarify that incremental changes are allowed without entire re-calculation.<br><br>MOD-004-1, B., R8, R9, R10, M11, M12, M13 use of the terms "tag" or "Interchange Transaction Tag" which is inconsistent with NERC INT and NAESB CI BP standards where specific reference to “tag” or “e-Tag” has purposefully been avoided in those standards. The term Request For Interchange (RFI) refers to a collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink BA. Or the term Arranged Interchange refers to The state where the Interchange Authority has received the Interchange information (initial or revised) and has distributed that information for reliability assessment. I believe that in these requirements, Arranged Interchange is the more appropriate language.<br>Response: The drafting team has modified the standard to use the term Arranged Interchange.<br>MOD-008-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider’s TRM methodology. This requirement to create a separate document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and TSPs two different documents to maintain.<br>Response: The standard does not preclude a Transmission Service Provide from using one document to meet both requirements.<br>MOD-008-1, B., R1.1 suggest modifying to read: “For each path or flowgate that ATC or AFC is calculated, describe how each of the following components of uncertainty are used in calculating TRM for each of the ATC time horizons (if not applicable, indicate as such):” The words “ATC time horizons” could be used to eliminate the need for R1.4.<br>Response: The drafting team intentionally avoided the use of the phrase “time horizons” in order to avoid confusion with NERC Compliance Time Horizons.<br>MOD-008-1, B., R1.1 suggest adding another item to the list. Variability and uncertainty in determining Transmission losses across Posted Paths.<br>Response: Losses are already included in the list as a part of the Load Forecast.<br>MOD-029-1, B., R1 (modeling requirements) should include the statement that the data listed below should reflect the expected conditions for the applicable time period.<br>Response: R1 has been modified to address this concern.<br>MOD-029-1, B., 1.6 Suggests this bullet be deleted. This is already addressed in R2 wherein the modeling process is dictated. In the RSP methodology, “peak load forecasts” are not used to stress the system; rather, load and generation are simulated to stress the system to its greatest capacity. There are cases when the highest forecasted load may not stress the system to its greatest utilization – which is the goal of the R2 under the RSP. |

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| | Response: The reference to "peak" load forecasts has been removed.<br>MOD-029-1 B., R5 definition of GF - The language describing Grandfathered capacity includes the defined terms "Firm" and "Transmission Service." Use of these words as defined terms is inconsistent throughout the proposed standards. They should either be changed here to a lower case or all applicable areas in each proposed standard should be changed to the defined term.<br>Response: The SDT agrees and has made the changes for consistency.<br><br>MOD-029-1 in R6, is the "non-firm capacity reserved for NITS" the same as Secondary Network Service (i.e., NN-6)?<br>Response: It is the same as Secondary Service and the requirement has been revised to reflect that.<br>MOD-029-1 in R7 & R8, what are "Postbacks"? This term is not used in the west. The term Postback should not be used in the RSP methodology.<br>Response: This term came from Order 890; to the drafting team's knowledge, it has generally not been used in the East or ERCOT either. The SDT believes that postbacks are used in the West (e.g. release of unscheduled firm as non-firm ATC), but are not referred to in this fashion. The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks.<br>MOD-029-1 in R5, R6, R7, & R8, calculation of ETC and ATC are commercial concerns and should be addressed in business practice standards NAESB and enforced through FERC's adoption of those business practice standards into the CFR.<br>Response: The drafting team does not believe these are only commercial concerns. If calculated correctly, ATC should be a reasonable approximation of what flows are expected on the system at a given point in time. Ensuring that this number is accurate will help ensure that entities do not oversell their systems into overloads.<br>MOD-029-1 in R8 ETC (Firm) definition, it uses the word "non-firm" and it should state "firm". We are assuming this is a typo.<br>Response: The SDT has corrected this typographical error.<br>MOD-029-1 in R8 the requirement says we are to use the same formula for all horizons – this is incorrect. For the real-time, same-day time frame, we release all unscheduled capacity as non-firm ATC. As such, the formula would read:<br>ATCNF = TTC – Scheduled ETCF – Scheduled ETCNF – CBMS – TRMU + Counter-schedulesF + Counter-schedulesNF<br>Response: It is the SDT's understanding that NAESB will incorporate unscheduled capacity in postbacks. The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks. Therefore, the requirement is correct as written. |
| Response: Please see in-line responses. | |
| Arizona Public Service Co. | Arizona Public Service Co. is in agreement with the WestConnect Comments and in general agreement with the WECC Comments. |

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| Response: Please see responses to WestConnect and the WECC MIC MIS ATC Drafting Team. | |
| Bonneville Power Administration | a. GENERAL<br>i.BPA supports retention of the three methods recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028).<br>ii. BPA supports the retention of the proposed one-year implementation period.<br>iii.BPA supports allowing NAESB to address all “posting” issues as they directly affect OASIS.<br>b. MOD-001<br>i.BPA supports allowing the use of more than one methodology for calculation of ATC by any one entity. For example, the Team supports allowing any entity to use the Flowgate methodology inside their affected area while also using the Rated System Path methodology at its boundaries.<br>ii. BPA supports allowing each entity to specify in its ATCID how it will treat counterflows.<br>iii.BPA supports the aggregation of transmission capacity for grandfathered contracts when shared with neighboring requestors.<br>iv.BPA supports the specifically limited universe of entities to which data sharing is required as prescribed in R10.<br>c. MOD-008<br>i.R2 – Add the following language to strengthen the distinction between TRM and CBM: “Transmission capacity required for the period immediately following a contingency and before the market can respond (up to 59 minutes following the contingency) are included in TRM”<br>Response: The language has been added.<br>d. MOD-029<br>i.BPA strongly supports retention of the requirement(s) in R2.2 that accommodate paths which are “flow limited” by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing and functional practices without re-inventing the wheel where no such effort is required to meet FERC’s goals of transparency and consistency.<br>ii.BPA strongly supports retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.<br>iii.BPA strongly supports retention of the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.<br>iv.BPA strongly supports retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts and potentially their associated operational agreements while supporting FERC’s mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation methodologies is required.<br>v.BPA strongly supports the adoption of the proposed Counterflow definition as its adoption clarifies the application of Counterflows in each equation.<br>e. MOD-030<br>i.R10 – It is assumed this requirement has been included to promote transparency, but will in fact have the opposite effect due to a flood of posted data being required that is not used to process requests, and therefore is not used by |

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| | market participants, and should be modified to the following: "The Transmission Service Provider shall provide a tool to convert…"<br>BPA has heard from a number of its Customers and other impacted parties that the posting of ATC, rather than AFC, will not promote transparency in the Northwest market or across BPA's system. BPA provides several tools on its website and OASIS site to facilitate interested parties' access to AFC-to-ATC conversions. These tools are easy to use and since a smaller quantity of data is posted to our OASIS site (i.e. 10 AFCs as opposed to several thousand ATCs), our OASIS system is more responsive and therefore, also easier to use.<br>Response: These standards do not address postings of these values. R10 simply describes how such values are to be converted. |
| Response: Please see detailed in-line responses. Thank you for your supportive comments. | |
| British Columbia Transmission Corporation | 1. MOD-028-1, R3.1 - We believe we understand the meaning of intra-day but are unfamiliar with the term intra-peak. Does this mean hourly peak?<br>Response: This language has been corrected.<br>2. MOD-028-1, R3.1, R3.2, R4.1, R4.2 - The parenthetical "(at a minimum)" is subject to interpretation. Does it mean that this is the minimum list of parameters to model or does it mean that these are the most conservative values allowed? If additional parameters or some other values are used, the references need to be specified somewhere. For example, if Peak Load is not used (because a higher TTC can be made available in shoulder hours), the ATCID needs a section describing what load to use. We suggest that "(at a minimum)" be replaced with "(or other values and additional parameters as specified in the ATCID)".<br>Response: The language has been modified to address this concern.<br>3. MOD-028-1, R7 - The process for calculating TTC should also the Transmission Operator to calculate TTC by interpolating between TTC values that have been calculated according to the process outlined. In complex systems with many assumptions in variables (e.g. load forecast, ambient temperature, generation dispatch), many possible limitations (e.g. thermal, transient stability, voltage stability, minimum voltage), and many single and multiple contingencies to run, it becomes impractical to calculate TTCs as described in R7. BCTC currently runs up to N-3 contingencies. BCTC, as well as an adjacent Transmission Operator, calculate TTCs using the process described in R7 for representative conditions, which on there own can require thousands of studies. TTCs for other conditions are then found by interpolation between the representative cases. Any margin we need to allow for "interpolation error" is much less that the margin we would need to allow if we generalize generation dispatch, ignore transient stability, or omit multiple contingency studies. Under no conditions do we extrapolate outside of the conditions bracketed by the studies. We propose an item f be added as follows:<br>f. When two or more transfer capabilities have been established according to the above procedure which bracket the requirements described above, the TTC can be determined by interpolation between these established transfer capabilities.<br>Response: The MOD-028 method requires an actual simulation of the system to calculate the TTC values. The drafting team does not believe an interpolation process conforms to the requirements of the standard. A deviation from this process could be obtained through a regional variance.<br>4. MOD-029-1, R4 - The double use of TTC is potentially confusing. At a minimum we suggest rephrasing R4 to be "at the lesser of the TTC calculated in R1".<br>Response: R4 has been changed to reference the "value calculated in R2." R3 and R4 have been reordered to |

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| | eliminate any confusion.<br>5. MOD-029-1, M1 - This measure is redundant. M4 requires that the TO produce the models, reports, or study results that it used to establish TTC. Since M4 already addresses models, M1 is redundant.<br>Response: The drafting team has deleted "models" from M4 to address. |
| Response: Please see detailed in-line responses. | |
| Clearwater Power Company | 1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.<br>Response: Please see responses to the WECC MIC MIS ATC Drafting Team.<br>2) In reference to MOD-030-1/R10, the requirement should be altered as follows: "The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC's for its network and provides a tool for AFC-to-ATC conversion (in BPA's case, Power Utilization Factor Calculators). We believe at this time that this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.<br>Response: The standards do not preclude the use of a tool to create ATCs from AFCs; nor do they require the posting of ATCs. |
| Response: Please see in-line responses. | |
| ColumbiaGrid, Inc. | Please see the comments below.<br>GENERAL COMMENTS:<br>a) ColumbiaGrid, a non profit corporation formed to promote the efficient operation, planning and use of the Northwest transmission grid, is generally supportive of the ATC Reliability Standards comments prepared by WECC. ColumbiaGrid believes that it is important to recognize and address the distinctive characteristics of the Western interconnected transmission grid. It should be noted that ColumbiaGrid has not attempted to address or comment on questions one through five, which address the specific language of the individual standards. ColumbiaGrid submits these general comments on its own behalf, not on behalf of its members or other participating parties, each of whom may submit general or specific comments on its individual behalf.<br>b) ColumbiaGrid supports the inclusion and need for all three ATC methodologies, recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028). ColumbiaGrid believes that retention of all three ATC methodologies is necessary to ensure that differences in structure and operation of regional and individual transmission systems are accurately and efficiently accommodated.<br>c) MOD-029 – ColumbiaGrid supports the need for this methodology, which is commonly utilized in the Western region.<br>Response: Thank you for your supportive comments.<br>d) MOD 030 - R10:<br>R10 states that the TSP shall convert Flowgate AFCs to ATCs for Posted Paths. Posted Paths is defined in MOD 1 as:<br>1. Any Balancing Authority to Balancing Authority interconnection; |

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<tr><td></td><td>2. Any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 month;<br>3. Any path for which a Transmission Customer requests to have Available Transfer Capability or Total Transfer Capability posted.<br>ColumbiaGrid is concerned that posted paths, as used in R10, could mean that AFCs must be converted to ATCs for any constrained POR/POD combination. ColumbiaGrid understands that this requirement has been included to promote transparency, but it may in fact have the opposite effect due to a flood of posted ATCs that are not used to process requests and of little value to transmission customers. BPA has provided a better alternative than converting AFCs to ATCs on constrained POR/POD combinations. BPA posts AFCs on internal flowgates and provides a tool for its customers to calculate the flow imposed on the flowgate relative to the POR/POD. ColumbiaGrid understands that BPA has heard from a number of its Customers and other impacted parties that the posting of ATC, rather than AFC, will not promote transparency in the Northwest market or across BPA's system. Further, ColumbiaGrid understands that BPA provides several tools on its website and OASIS site to facilitate interested parties' access to AFC-to-ATC conversions. These tools are easy to use and since a smaller quantity of data is posted to BPA's OASIS site (e.g. approximately 10 AFCs as opposed to potentially several thousand ATCs), BPA's OASIS system will likely be more responsive and therefore, also easier to use. ColumbiaGrid believes that this method eliminates burdensome postings of multiple POR/POD ATCs.<br>ColumbiaGrid proposes that R10 be modified as follows: "The Transmission Service Provider shall provide a tool to convert AFCs to ATCs for posted paths…"<br>Response: The standards do not preclude the use of a tool to create ATCs from AFCs; nor do they require the posting of ATCs.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Consumers Power, Inc.</td><td>1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.<br><br>Please see responses to the WECC MIC MIS ATC Drafting Team.<br><br>2) In reference to MOD-030-1/R10, the requirement should be altered as follows: "The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC's for its network and provides a tool for AFC-to-ATC conversion (in BPA's case, Power Utilization Factor Calculators). We believe at this time that this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.<br>Response: The standards do not preclude the use of a tool to create ATCs from AFCs; nor do they require the posting of ATCs.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Duke Energy</td><td></td></tr>
<tr><td>Entergy Services Inc.</td><td>SDT has done a great job!!!</td></tr>
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| Response: Thank you for your supportive comment. | |
| EPSA | EPSA would like to provide the following additional comments:<br>1. MOD 001-1, R3.1 (similar language is used elsewhere) provides that information will be provided "in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC calculations may be validated." However it is also noted on page 4 of this document above, that all posting requirements will be as determined in the associated NAESB standards. While we are aware of the coordination with NAESB that is on-going and we are actively participating in it, EPSA's assessment of the appropriateness of this requirement can not be completed without knowing the outcome of the related NAESB standard drafting work that is on-going.<br>Response: It is the intention of the drafting team to define documents that are needed for reliability purposes (in this case, so that other reliability entities may be aware of the processes and procedures used by their neighbors). This does not preclude NAESB from using this information to meet their transparency and disclosure goals, but it is not necessarily the intent that these documents support only NAESB efforts.<br>2. MOD 004-1, the CBM standard incorporates a number of principles with respect to allocation of CBM, both at the time of ATC calculation and at the time of scheduling deliveries, which EPSA summarizes as follows. CBM, by virtue of being determined as a "set-aside" has priority over all purchases of transmission service, even firm service. This extends into future time frames in that R4.3 states that, if there is initially insufficient CBM to meet all requests, any new interface capability coming available would be allocated first to unfilled CBM requests. Furthermore, when scheduling CBM, LSE's are entitled to utilize any available CBM, not just the quantity that they have requested.<br>EPSA accepts the notion of a set aside for CBM, contingent on acceptance of some additional principles.<br>CBM should be purchased by eligible LSEs at full embedded cost of the transmission. This is clearly a superior service that is being provided-it should not be available at a reduced cost.<br>Response: The NERC standard does not intend to provide any specific guidance on how much CBM should cost.<br>In the event of an emergency at level EEA2 or higher, LSEs are granted access to all CBM reserved, even if reserved by other LSEs. EPSA acknowledges that under such emergency conditions, all possible accommodations should be made. However, this accommodation together with the charge for service as discussed above, provides considerable incentive to under-reserve CBM. As LSEs are required (R3.2) to update their CBM requirements at least every 31 days, scheduling beyond their reserved amount at the time of an emergency should be investigated, after the fact, for possible violation of this requirement.<br>Response: Such investigations may be necessary to ensure no hoarding or under-reserving of CBM occurs. Those related to reliability will be handled through the NERC processes; those related to pricing and open access will likely be addressed through other processes.<br>R4.3 notes that CBM is made available as a set-aside, such that LSE's are granted priority access to available service, including service that becomes available in future if not all requests can be accommodated initially. Such priority access to future quantities should not receive priority over duly granted roll-over rights.<br>Response: R4.3 has been removed.<br>3. MOD 001-R4 and R5 define the default values for counterflows to be used in the calculations of firm and non-firm ATC. As stated, these values are extremely conservative. R4 and R5 should require an explanation, based on modeling or based on historical values, of whatever values of counterflows are adopted by the TSP.<br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments |

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| | provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules. |
| Response: Please see detailed in-line responses. | |
| ERCOT | For the entire ERCOT Interconnection, the market rules that govern establish, under Texas State Law, that the transmission system is to be operated in an open access process, much as a common carrier. As such, there is not a Transmission Service Market in the ERCOT Interconnection. Therefore, ATC, TTC, CBM, and TRM are not applicable within ERCOT operations. These Standards should have provisions that make it clear that these requirements apply only within market structures in which they are pertinent. |
| Response: These standards are intended to apply to all entities described in the "Applicability" portion of the standards. Paragraph 160 of Order 890 provides ISOs and RTOs the means through which they can request to be exempted from the requirements of the Order, and NERC has similar provisions through which exemptions from the requirements of this standard may be pursued. These standards do not address the selling of service, and instead only apply to the determination of ATC (i.e., determining the difference between the capability of the system and the forecast use of the system).<br><br>Note that given the new definition of ATC Path, if ERCOT is not required to post ATC for any paths, then ERCOT would only be required to implement MOD-001 R3, R4, R5, and R8; all other requirements, as well as MOD-028, -029, and -030, would not apply. If ERCOT does not maintain CBM, it would be exempt from MOD-004. If ERCOT does not use TRM, it would be only be required to implement MOD-008 R1 and R3; all other requirements would not apply. | |
| Fall River Rural Electric Cooperative, Inc. | 1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.<br>Response: Please see responses to the WECC MIC MIS ATC Drafting Team.<br><br>2) In reference to MOD-030-1/R10, the requirement should be altered as follows: "The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC's for its network and provides a tool for AFC-to-ATC conversion (in BPA's case, Power Utilization Factor Calculators). We believe at this time that this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.<br><br>Response: The standards do not preclude the use of a tool to create ATCs from AFCs; nor do they require the posting of ATCs. |
| Response: Please see in-line responses. | |
| FirstEnergy Corp. | 1. MOD-001-1:<br>- R2 & R9 - There is no calculation requirement for yearly ATC in R2 or R9. Yet in MOD-004-1, R3.1 requires the identification of a CBM amount for, "each month for each year for the next ten year period."<br>Response: MOD-004 and CBM are different from ATC. The drafting team believes that CBM requires this longer-term analysis to support long term planning.<br>- R6 - In addition to notification, before implementation of a new ATCID, the Transmission Service Provider should |

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| | allow for a comment period. This will assure that all the affected entities have been given an opportunity to provide valuable clerical and technical input on the document.<br>Response: While entities may elect to offer such comment and peer review periods, the team did not mandate such reviews to ensure that the ability to address necessary changes quickly was allowed.<br>- Counter-flow calculations in the past were difficult to justify and manage. This standard attempts to manage counter-flows by requiring TSPs to specify their accounting method in the ATCID, but does not require any justification of the method used for applying them. This situation could result in inconsistency in ATC calculations and application. Requirements should be developed that govern the calculation and application of counter-flows to ensure consistency and transparency.<br>Response: The drafting team has modified the approach to counterflows in the standards. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID. Further standardization of counterflow treatment in ATC calculations could conflict with the requirement to use assumptions in the ATC calculation that are consistent with those used in planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br>2. MOD-004-1:<br>- The need for LSE involvement in setting CBM levels is completely dependent on the Resource Adequacy Requirement structure, and for some structures it would not be appropriate for LSEs to have input into the CBM calculation. For example, in PJM, an individual LSE (1) may not know if there is enough capacity in the market to meet reliability needs, or even what are the specific resources serving their load; (2) may have no responsibility to identify specific capacity resources beyond the obligation to purchase capacity credits from unspecified sources. Overall capacity management, short-term and long-term reliability responsibility, resides at the ISO level.<br>Response: Your comment is correct and the standard has bee modified to address your concerns by including Planned Resource Sharing Groups.<br><br>- In general, this standard may lead to situations that cause CBM reservations to be excessively higher than needed. There is no reference to a CBM calculation methodology, leaving LSEs free to request CBM on any basis. Many LSEs do not have the necessary tools needed to make proper CBM calculation, which could lead to simplistic and conservatively high CBM requests.<br>Response: The drafting team was specifically silent on the methodology used to determine the amount of GCIR and/or CBM required, as we agree – the procedures and regulatory requirements associated with this determination vary significantly. To the extent an LSE does not have the tools need, they would be expected to either acquire those tools or work with a third party to develop their request.<br>- Further compounding the problem of over-reserving CBM is the provision that calls for the TSP and TP to set the aggregate CBM level as the sum of all LSE requests such that all requests can be met simultaneously. It is unlikely all LSE adverse scenarios will occur. It is even more unlikely that all will occur at the same time. These provisions will result with too much CBM being set aside. Diversity is not taken into account.<br>Response: The drafting team chose this course of action because of potential conflicts with state or local regulations. If a state mandates that entity X rely on 200MW worth of external resources for generation adequacy, and mandates entity Y rely on 200MW as well, these two entities may make separate requests to the TSP, each requesting 200MW. |

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| | If the TSP only grants 200MW of CBM, and a capacity emergency occurs that impacts both entities, then there will not be enough CBM. Rather than put the TSP and LSEs in this position, the standard is requiring the TSP grant what he is asked for, and giving LSEs the opportunity to make joint requests, directly or through a third party, so that aggregations such as you describe can occur – but only with the LSEs knowledge and consent.<br>- There are no provisions for the TP or TSP to challenge unreasonable CBM requests.<br>Response: The LSEs are responsible per R3.3 for making reasonable requests, and are subject to sanctions if they do not.<br>- This standard does not incorporate the resource adequacy criteria into the process of setting the total CBM value. The simple summation of CBM requests ignores the uncertainty associated with the scenarios behind the CBM requests.<br>Response: This is true. The drafting team was specifically silent on the methodology used to determine the amount of GCIR and/or CBM required, as the procedures and regulatory requirements associated with this determination vary significantly.<br>- R2 - "CBID" should be "CBMID"<br>Response: The SDT has corrected this typographical error.<br>- R3 & R4 - A monthly value is extremely difficult to administrate and implement in the ATC calculation. Such a requirement will incur significant cost and subject the TSP to significant increases in cost. We suggest leaving it to each region to decide on the time intervals.<br>Response: The intent of this standard is to require incremental changes and not recalculation of the GCIR. The standard has been modified to address your concern.<br><br>- R3.1 – This section should be clarified. It states “requested for each month for each year for the next ten year period.” Do we really want 120 months worth of requests, or 12 monthly requests and 9 yearly?<br>Response: The drafting team has changed the standard to clarify what is required.<br><br>Also, the ATC postings only cover at most a 12 month period in MOD-001-1. Why is it necessary to have such a disparity in the period of coverage?<br>Response: CBM is not just required for ATC, but also for transmission planning.<br><br>R3.2 requires updating this CBM request at least every 31 days to reflect any changes that alter future needs. New development projects influence future needs for load growth. The probability that these projects will come to fruition can change from month to month. Is it reasonable to require a ten year look ahead to be revised on a 31 day cycle?<br>Response: The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. We are requiring that entities update their CBM at least once a month to ensure that no unneeded CBM is still being held back from the market. The intent of this standard is to require incremental changes and not necessarily recalculation of the GCIR. The standard has been modified to address your concern. |

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| | - R3.1.1 - In some areas it may not be possible that CBM can be determined from GCIR at the LSE level, especially if the standard will require data ten years in the future. In retail choice areas, an LSE has few load responsibilities (therefore resource responsibilities) for more than a couple years.<br>Response: If the LSE does not know their need more than two years out, then they should request zero or their best estimate for those later years.<br>- R3.1.1.1 - CBM will be called upon in an emergency. We are not sure that it is feasible to identify the Balancing Authority or Posted Paths in all areas. We assume CBM would be used to bring in the most appropriate resources at any given time, but can that be known now for an emergency in the future?<br>Response: If entities are requesting CBM, it is reasonable to expect them to have an idea where the energy will be coming from. CBM is not intended to be a generic margin on all paths in case it is needed (like TRM), it is intended to be a margin based on a potential use.<br>- R3.1.2 - The basis for the request of CBM is not clearly defined. This requirement indicates that GCIR must be based on standards, criteria, established by other authorities. The LSE must document the Resource Adequacy Requirement (RAR) standards & authorities that form the basis of their request, and all details of the associated resource studies. This implies that it is a clear, objectively-determined parameter, yet it does not say how any particular elements of the results of the RAR study fit into the GCIR calculation.<br>Response: The standard does not intend to require any specific methodology or basis for determining GCIR. LSEs are expected to follow whatever study parameters or guidelines are required by their regulator.<br>- R4.1 either contains an extra colon that should be deleted, or is missing "(TRM"<br>Response: This has been corrected.<br>- R4.3, R5.3, and R6 address the idea that the sum of all requests may be greater than the available capacity on the facility and directs the CBM to be increased based on availability up to the sum of all CBM requests. The standard is silent on what is to be done if the sum of all requests is greater and no additional capacity is made available on the facility. The standard should include the method for allocating the requests in this situation.<br>Response: Since CBM is a margin (not a reservation), allocation is not necessary. Any entity is entitled to use CBM if needed and it is available, regardless of how much was requested or granted. When not all requests can be granted simultaneously, all customers will be notified of this fact.<br>- R9 - Should be adjusted so that it explicitly states that only the timing requirements for the Real-Time market only will be waived. For example, the Day-Ahead Market timing requirements cannot be waived.<br>Response; The standard has been modified to incorporate this suggestion,<br>- R8, R9 & R10 - This standard refers to Interchange Transaction Tags. This has become problematic in that there are no requirements to tag interchange transactions in the NERC Standards posted on 10/23/07 with one exception. INT-004-1 still requires a modification to the tag for dynamic interchange transaction modifications. IRO-006 still relies heavily on interchange transaction tags for the TLR procedures, but without a requirement to tag a transaction, it is not clear how this procedure is accomplished under today's standards. Until transaction tags are required by the standards, the references in R9 and R10 that rely on interchange transaction tagging should be revised.<br>Response: We have revised these requirements to reflect the terms use in the Interchange standards.<br><br>3. MOD-008-1: |

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| | - R1.3. - Should be revised to state the description of the method used to allocate TRM across Posted Paths or Flowgates. As currently stated, it appears to be a list of Posted Paths or Flowgates with a TRM value or percentage assigned.<br>Response: The requirement has been modified to incorporate the suggested change.<br>- R3 - Should be revised to state within seven calendar days of the receipt of a written request.<br>Response: The SDT has incorporated the suggested change.<br>- R4 - Should be revised to state within seven calendar days of the receipt of a documented request for such information.<br>Response: The SDT has incorporated the suggested change.<br>4. MOD-028-1:<br>- R5.3 - The requirement states, "If the source has not been specified, use the interface point with the adjacent upstream Transmission Service Provider as the source." It may be difficult to determine the upstream Transmission Service Provider when the source has not been specified. The same is true for "If the sink has not been specified, use the interface point with the adjacent downstream Transmission Service Provider." These statements should be revised to state, "If the source has not been specified and the sink has, use the interface point with the adjacent Transmission Service Provider upstream from the source as the source." And "If the sink has not been specified and the source has, use the interface point with the adjacent Transmission Service Provider downstream from the sink as the sink."<br>Response: The SDT has modified this requirement to be more explicit, as well as allow for more flexibility based on specifications in the ATCID.<br><br>- R11 & R12 - Use the term "postbacks" that is not defined in the NERC Glossary nor is it well defined in this standard. It appears the requirement is communicating that it is defined in Business Practices. We suggest it be defined in the ATCID much like the Counterflows are described in the ATCID.<br>Response: The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks.<br>5. MOD-029-1:<br>- R7 & R8 - See our comments regarding "Postbacks" above.<br>Response: See response regarding "Postbacks" above.<br>6. MOD-030-1:<br>- R2.1.2 - The phrase "first three limiting" is too prescriptive and should be removed. For example, if the most limiting first contingency transfer is a large value, say 10,000, adding the first three limiting elements/contingency combinations is not necessary. If the requirement cannot be removed, we suggest adding wording that sets a transfer level such that the first three constraints that cause the FCITC to fall under that level will be captured. Also, "source sink combinations" needs to be further defined as a calculation; an entity of any size could have thousands of these possible combinations. Also, if this in-depth study is required, the frequency in R2.2 should be decreased (as this is a minimum standard to maintain the reliability of the BES). |

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| | Response: The requirement could create some unneeded flowgates, but the SDT feels that this is not overly burdensome to those using the flowgate methodology. In order to maintain reliability the SDT believes that the minimum of the first three limiting Elements/Contingency combinations within the Transmission Operator's system being included as Flowgates is required. The SDT has modified R2.1.1. and R2.1.2 to include the phrase, “up to the path capability”. The source sink has been changed to POR POD in R2.1.2. The frequency in R2.2 has been modified to annually.<br><br>- R4 - The requirement states, “If the source has not been specified, use the interface point with the adjacent upstream Transmission Service Provider as the source.” It may be difficult to determine the upstream Transmission Service Provider when the source has not been specified. The same is true for “If the sink has not been specified, use the interface point with the adjacent downstream Transmission Service Provider.” These statements should be revised to state, “If the source has not been specified and the sink has, use the interface point with the adjacent Transmission Service Provider upstream from the source as the source.” And “If the sink has not been specified and the source has, use the interface point with the adjacent Transmission Service Provider downstream from the sink as the sink.”<br><br>Response: The SDT has modified this requirement to be more explicit, as well as allow for more flexibility based on specifications in the ATCID.<br><br>- R5.2 - It is not clear to us what the definition of a "third-party" is and how it is used in AFC calculations. Please clarify.<br><br>Response: The old R5.2 (now R5.3) was modified to remove third party and clarify language as, “Transmission Service Provider that calculates AFC for that Flowgate as the AFC.”<br><br>- R8 & R9 - See our comments regarding "Postbacks" above.<br><br>Response: The SDT has clarified the term post back by incorporating the following definition: “Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.” Note that NAESB will be defining specifically what values should be considered when determining Postbacks.<br><br>- R9 - "Counterflows" is missing subscript "NFi" in the formula.<br><br>Response: While the adjustments may be based on the impacts, business practices may dictate the actual value used. Therefore, the SDT has chosen to not include the “i.” The same is true for postbacks.<br><br>7. MOD-001-1 (R7, R10), MOD-004-1 (R2), MOD-008-1 (R4), and throughout other standards the drafting team uses the phrase, “make available.” In addition, per FERC Order 693 (e.g. Par. 1023), wording should be added as to how it needs to be made available, such as on a website. Furthermore with regard to the sharing of information, requirements in these standards that require an entity provide information to another entity should have a standard method for providing the information or at a minimum require a negotiated method and format for providing the information. This will also require dispute resolution when two entities cannot agree on a method or format.<br><br>Response: The SDT used the words “make available” to allow for flexibility. If entities wish to make this information available via a website, that is acceptable. With regard to data exchange, the same is true. Note that NAESB may elect to draft business practices to address this concern as well. |

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| | 8. These standards do not address the market operation methods in use today. Currently, the Transmission Service Providers are the RTOs in some markets. These entities are also the market operators and not-for-profit organizations that have no vested financial interest in the amount of TTC assigned to a flow-gate or transmission facility. The modification of these standards to place the burden on the Transmission Operator for these calculations is a significant step backwards that should be revised to avoid the need for waivers or delegation agreements and to meet the needs of the old method of operation and the new market methodology.<br>Response: The SDT believes the functional model has the Transmission Operator as responsible for calculating the TTC. If an RTO is performing this function, the team believes they are performing it on behalf of their Transmission Operator.<br>9. Several requirements related to ATC have been incorporated into NAESB standards. It would be beneficial for these standards to be more transparent to the industry since it is challenging to find these standards on NAESB's website or some other means. It may help to have a direct link to these business practices on NERC's website in the future. Furthermore, it may help to incorporate these NAESB standards into NERC's standard review process for this and future projects in an effort to achieve full industry input on the development of these practices.<br>Response: NAESB standards are handled through the NAESB process, which is an open and ANSI-accredited process. The SDT encourages entities to participate in the NAESB process.<br><br>10. This set of ATC standards may need to go through a field test to determine how effective these calculations for ATC can be based on all the new requirements for Implementation Documents and Applicability to Transmission Operators and Load Serving entities that may not have ever dealt with these sorts of calculations in the past. If a field test is not an option due to time constraints, then the effective date should be pushed out another 12 months.<br>Response: The majority of responses to Question 1 of this comment solicitation indicate that 12 months is an acceptable implementation period. The majority of entities did not request a field test. |
| Response: Please see in-line responses | |
| Flathead | 1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.<br><br>Please see responses to the WECC MIC MIS ATC Drafting Team.<br><br>2) In reference to MOD-030-1/R10, the requirement should be altered as follows: "The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC's for its network and provides a tool for AFC-to-ATC conversion (in BPA's case, Power Utilization Factor Calculators). We believe at this time that this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.<br>Response: The standards do not preclude the use of a tool to create ATCs from AFCs; nor do they require the posting of ATCs. |
| Response: Please see in-line responses. | |

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| FRCC | MOD 28 Requirements, Measures and VSLs for R9-R12 are not explicit that setting a value to "Zero" is "using" the value. This could cause confusion on audits. R9-R12 should be revised to indicate that "Zero" is an acceptable value and qualifies as "using" the element. For example under each item where the elements are defined a line could be added stating. "The Transmission Service Provider shall show all elements of the calculation even those that have a value of zero for the path being calculated, and that value of zero for an element is considered using the element."<br>Response: The SDT has added language to the measures in the standards to explicitly allow the use of zero.<br><br>MOD-001-1: ATC: The frequency of calculation in R9 for the same products in R2 adds little or no accuracy or value to the results, particularly towards the end of the horizon. For example, hourly ATC must be re-calculated for three to seven days out every hour, the same as for two to four hours out. This should be relaxed to a tiered requirement. The postings should be made out to 168 hours, however, the frequency could be relaxed so that the outer bounds of the horizon are updated less frequently. (i.e. R9.1 For next 4 hours, once per hour, for hours beyond 4 hours out until end of next day (midnight), once every 6 hours, for hours beyond end of next day, once per day.)<br>Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br>MOD-001-1: ATC: R10 is exhaustive. The requester should be required to have cause to request such information and be required to pay for the administrative costs of collecting and transmitting the information. Much of the listed information is embedded within the power-flow models, and transmitting models electronically on an hourly basis to potentially multiple requesters would be very costly and time-consuming. If a requester has a grievance or dispute, then the historical data should be sufficient to provide for the calculations in question.<br>Response: This information is not intended to be used to address grievances or disputes… it is intended to improve the accuracy of the ATC calculation. All transmission providers are expected to meet this requirement as part of their cost of doing business reliably.<br>MOD-028-1: Area Interchange Methodology: R7 – In step 'a' the 5% distribution factor should be specified as OTDF or PTDF (should be OTDF).<br>Response: The distribution factor is meant to refer to PTDF or OTDF.<br><br>MOD -028-1: R7 – in Step 'A' the 5% distribution factor appears to only apply to adjacent systems. This could result in a scenario where Utility B prudently limits ATC based on a facility in their system between them and Utility C, however Utility A allows a transaction to C that has the same impact on the same facility because of the 5% rule. We suggest that the ATCID should specify the handling of off system non path impacts.<br>Response: The Drafting Team has modified the second bullet of the requirement as follows:<br>"-A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is greater than 5%. The Transmission Operator may honor distribution factors less than 5 %."<br><br>MOD-028-1: In R7 step 'c', Please further define "all impacts of firm transmission service included in the study model" and/or provide an example. In our region this phrase was interpreted by some to mean "firm point to point only" and by others to include network and native service. |

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| | Response: The Drafting Team has clarified the language as follows:<br>"-The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as described in the Transmission Service Provider's ATCID, that were included in the study model, or."<br><br>MOD-029-1 R1 This section should specifically say that all the BA-BA transactions are removed from the load flow model. These transactions are accounted for under ETC.<br>Response: In the Rated System Path methodology, the model is used to determine TTC, which is the "unloaded" capability of the system. There is not necessarily a relationship between the schedules used in the model and simulation to determine TTC and the schedules and reservations used to determine ETC.<br><br>MOD-29-1 R1-6 This section implies that load is in the model which means the TTC calculated would be reduced due to the load. In MOD-29-1 R5 load is again accounted for under ETC. It appears that the equation for ATC in MOD-29-2 R7 double counts the effect of load because it is included in the TTC and in ETC.<br>Response: Response: In the Rated System Path methodology, the model is used to determine TTC, which is the "unloaded" capability of the system. There is not necessarily a relationship between the schedules used in the model and simulation to determine TTC and the schedules and reservations used to determine ETC.<br><br>Mod-29-1 R5 More detail is needed as to how the components of ETC are to be determined from a load flow model. Particularly, NLF, NITSF and GFF.<br>Response: ETC components are not derived from simulation in the Rated System Path methodology. The standard does not define the specifics of how these are determined, other than requiring their inclusion within the ATCID as described in R3.1.<br><br>MOD-029-1 R7 C: Assuming no other changes this sentence should be revised to state "Determine the impacts of Firm Transmission Service that were included in the study model." The summing of this item with the incremental Transfer Capability occurs in Step D and mentioning it here in C is redundant.<br>Response: There is no MOD-029 R7C.<br>Mod 28 R7c: This term should have a defined variable name or acronym.<br>Response: The drafting team does not believe that a variable name or acronym is required, and that the language is clear as written.<br>Mod 28 R7c, R9, R10, R11, R12: In R7c the "impacting firm transmission service" is determined and summed to the ITC results to get the TTC. In R9 & R10 an ETC is determined then in R11 & R12 that is deducted from the TTC to get ATC. However there is no tie made between the undefined "impacting Firm Transmission Service" R7c and the ETC in R9 & R10. So there is no requirement that would prevent a service from being modeled in the model, not included in the "Impacting Firm Transmission Service" (IFTS) but then included in the ETC calculation, thereby effectively double counting the service. The service was on in the model, thereby reducing the capacity, the service was not added to the model in the IFTS but was deducted from the capacity in the ETC as if it wasn't running in the model.<br>Response: R7c has been changed to require the Transmission Service Provider to document their process of how |

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| | they accounted for the impacts in the TTC calculation in their ATCID.<br><br>We suggest that the drafting develop a set of examples to clearly explain the principles and calculations laid out in the standards to help insure uniformity in interpretation of the standards. See that attached example, which while basic, could be modified to emphasize specific concepts like CBM, Postbacks, Counter Flows, TRM, "Impacting Firm Transmission Service", etc.<br>Response: The drafting team will investigate the possibility of creating a reference document to accompany the standards. |
| Response: Please see in-line responses. | |
| Georgia Transmission Corporation | MOD-001-1, R10 requires "within fourteen calendar days" for a TSP to begin supplying large amounts of data used in calculations. "Within thirty calendar days" is more realistic to supply large amounts data that could be extensive and detailed.<br>Response: This change has been incorporated.<br>MOD-004-1, R2 requires a TSP to act within 7 calendar days, R6 requires a TSP to act within 5 calendar days, R7.1 and R7.2 require a TSP to act within 7 calendar days. R2, R6, R7.1 and R7.2 should be changed to match the 14 calendar days required by R4. 14 calendar days is more appropriate for data requests that are "reports", "supporting data", documentation, work papers, etc.<br>Response: R2 has been modified to require provision before the effective date of the document. R6 has been retained at 5 days, as the drafting team does not believe this to be onerous. R7.1 and 7.2 have been extended to thirty days.<br>MOD-008-1 R3 and R4 require "seven calendar days" for a TSP to act. 14 calendar days is more appropriate for data requests that are "underlying documentation, work papers…", etc.<br>Response: R3 has been extended to thirty days. R4(which is now R5) remains at 7 days.<br>MOD-028-1, R5, it appear that the word "shall" is not needed in the following sentence. "-If the sink has been specified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink."<br>Response: The SDT has corrected this typographical error.<br>MOD-028-1, the VSL for R8 is missing a measurement: The Transmission Operator has not provided its Transmission Service Provider with its Posted Path TTCs within ___ (should be seven) calendar days of their determination, but is has not been more than 21 calendar days since their determination.<br>Response: The SDT has corrected this typographical error. |
| Response: Please see in-line responses. | |
| Hydro One Networks | MOD-028-1(Area Interchange Methodology) VSL Requirement 2: The requirement talks about Facility ratings from both Transmission Owners and Generator Owners. The associated VSL description forgot to include Generator Owners.<br>Response: The SDT has corrected this oversight.<br>As well, this VSL talks about not using a certain number of Facility Ratings which I assume would result in some TTC |

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| | error therefore I would propose changing how this requirement is measured:<br><br>Lower VSL: 1%<TTC error<5%<br>Moderate VSL: 5%<TTC error < 8%<br>High VSL: 8%< TTC error < 10%<br>Severe VSL: TTC error > 10%<br><br>As well this can be used for R3 and likely several other requirements were TTC and ATC errors can result from non-compliance.<br>Response: The drafting team discussed the proposed change and determined that relating the violation to the number of facility rating errors that directly affected the TTC was a more appropriate measure than trying to find a percentage that would apply fairly to all sizes of TTC. As a result of your comment, the drafting team has adjusted the VSL section of the standard as follows:<br>An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized. |
| Response: Please see in-line responses. | |
| Hydro-Québec TransÉnergie (HQT) | MOD-001<br>1. R1: While in many cases, the decision on which ATC methodology to use may be made jointly between the TSP and TOP. However, since you cannot have joint responsibility in the standard, the TOP is the appropriate Functional Model entity.<br>Response: The SDT concurs with your assessment.<br>Acronyms TSP, and TOP need to be defined in the Background Information on p. 3.<br>Response: These are defined in the glossary; the background was not intended to be part of the standards.<br>2. R8: Since this standard deals with short-term Transmission Service, the reference to planning studies should be removed from R8<br>Response: While this standard deals with short-term service, it requires that assumptions used in that short-term analysis are consistent with those used in the long term. The SDT does not believe this to be in conflict.<br><br>3. R8 is an appropriate representation of the broad FERC requirement as-written that will force entities to make a conscious effort to ensure this consistency occurs. While the language is somewhat vague, we recognize that adding more detail would be unreasonably difficult. We would suggest that detail be added in the measures to provide examples of what a valid demonstration would be. For example, TOP/TSP may provide evidence to demonstrate that the source of the inputs used in the operational studies is the same as for the TTC/ATC studies.<br>Response: The Drafting Team could not develop a comprehensive, exclusive list of assumptions, but has added a partial list of examples in the measure, M6.<br>TOP and TSP need to be defined in the Background Information on p. 3.<br>Response: These are defined in the glossary; the background was not intended to be part of the standards. |

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| | MOD-028<br>1. R8 should be broken down into the different timeframes; sending TTC values used in hourly and daily ATC calculations seven days after being calculated is too late. Suggest: 8.1 within one calendar day of its determination for TTCs used in hourly and daily ATC calculations; 8.2 within seven calendar day of its determination for TTCs used in monthly ATC calculations.<br>Response: The SDT has modified the standard to incorporate the suggested change. The following modifications were made:<br>R8.1.One calendar day of its determination for TTCs used in hourly and daily ATC calculations<br>R8.2. Seven calendar day of its determination for TTCs used in monthly ATC calculations.<br>MOD-030<br>1. R4 seems duplicative of MOD-001 R8<br>Response: The Standard Drafting Team agrees. R4 has been edited to remove this duplication.<br><br>2. R6.3, 6.4 - The last sentence of R6.3 seems to belong in 6.4 not 6.3<br>Response: The SDT has corrected this typographical error. |
| Response: Please see in-line response. | |
| IESO | MOD-028 and MOD-029: We raise the question on the "purpose" of both MOD-028 and MOD-029, both of which are defined as: "...to support reliable system operations". Is the methodology to be used for calculating transfer capability for "Transmission services", or for supporting reliable system operations? For entities which do not provide physical point-to-point transmission services, like the IESO, why should we be held responsible for meeting the standard requirements for calculating TTCs that support transmission services?<br>Response: The Drafting Team removed the reference to Transmission Service.<br>MOD-030<br>Several requirements are written with sub-requirements that are really criteria. These sub-requirement should be incorporated directly into the requirement itself. Otherwise, we risk having the Commission assign a VRF to something that really is criteria or explanatory text. Some examples include R2, R3, and R4. R2 could be written as:<br>R2. The TSP shall identify Flowgates for use in the AFC process based on the following minimum criteria.<br>- Flowgates should be defined with contingencies that are used in operations and planning studies for the associated time horizon.<br>-At least the first Flowgates identified as limits to transfer from or to all adjacent BA within the TOP transmission system.<br>-Any modeled Flowgate that has been subjected to Interconnection wide congestion management procedure or another TP using methodologies defined by MOD-28 or MOD-29 has requested that meets one of the following two criteria.<br>-Any generator within the Transmission Service Provider area has at least a 5% PTDF or OTDF impact on the |

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| | Flowgate when delivered to aggregate load in the TSP areas or<br>-A transfer from any BA within the TSP's area to a BA adjacent that has at least a 5% PTDF or OTDF impact on the Flowgate<br>We agree with that the remaining sub-requirements of R2 are really sub-requirements.<br>Response: The standard drafting team has reviewed all of the sub-requirements and has made adjustments where appropriate.<br>R4 should be rewritten as because the assumptions should be specifically designed and it is too vague:<br>R4 The Transmission Service Provider shall use contingencies from it planning and operating studies for the applicable Time Horizon and should model the impact of point-to-point Transmission Service as:<br>- When the source or sink are specified in the reservation, the Transmission Service Provider should model the reservation in the following order of importance:<br>1. Model the reservation using the actual source and sink in the model.<br>2. Map to an "equivalence" or<br>3. Map to the interface point with the adjacent upstream Transmission Service Provider as the Source the adjacent downstream Transmission Service Provider as the Sink.<br>- When the source or sink are not specified, the Transmission Service Provider should map the reservation to the interface point with the adjacent upstream Transmission Service Provider as the Source the adjacent downstream Transmission Service Provider as the Sink.<br>Response: The SDT has modified the language to be clearer, and have also allowed for more flexibility by providing for source/sink processing rules to be specified in the ATCID.<br>R2.2 should also require a change to flowgates any time there is a topological change that impacts one.<br>Response: The SDT does not believe that this should be a requirement since there are other methods to incorporate the impacts of topological changes. This requirement does not disallow updating flowgates more often or for topological changes.<br>The VSLs for R1 need to be defined according to the Violations Severity Levels Development Criteria document. R1 fits the procedure/program category. Lower, Moderate and High VSLs should be defined based on some of the criteria being included.<br>Response: The VSLs have been updated to incorporate two levels.<br>Counterflows - the treatment of counterflows is mentioned in all the MOD standards - MOD-001, MOD-028, MOD-029, and MOD-030 - all the formulae incorporate counterflows into the calculations but there seems to be a disconnect between the formulae and R5 of MOD-001 - if counterflow treatments are left to the discretion of the TSP in the respective ATCIDs, then why does R5 of MOD-001 exist - can it not be written as: "When determining the impact of counterflows in the determination of non-firm ATC or Available Flowgate Capability (AFC), the Transmission Service Provider shall apply counterflow treatment consistent with the Transmission Service Provider's ATCID". The counterflow treatment should also be consistent with transmission planning studies.<br>Response: The drafting team has modified the approach to counterflow in the standards based on the comments provided. The default values were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The |

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| | Drafting Team modified the requirement for the ATCID in MOD-001 to include more detail regarding how the TSP handles counterflows. With this approach we do not believe that a definition of counterflow is required. Assumptions in ATC calculations should be consistent with assumptions used in operation studies and planning studies for similar time horizons.<br><br>We agree with the NERC SDT that the TRM methodology should not be prescriptive.<br>Response: Thank you for your supportive comment,<br>MOD-008 (TRM) has a requirement when entities have a zero value for TRM - R1.5 of MOD-008 states that: "If TRM is zero for all the time periods…".There is no similar language for MOD-004 when entities have a zero value for CBM.<br>Response: The SDT has modified the standard to clarify that the communication of fact that TRM is not used is what is required. |
| Response: | |
| ISO/RTO Council (IRC) | MOD-029 RATED SYSTEM PATH TTC, ETC & ATC<br>1) The SRC supports retention of the requirement(s) in R2.2 that accommodate paths which are “flow limited” by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing practices without re-inventing the wheel where no such effort is required to meet FERC’s goals of transparency and consistency.<br>Response: Thank you for your supportive comment.<br>2) The SRC supports retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.<br>Response: Thank you for your supportive comment.<br>3) The SRC supports retention of the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.<br>Response: Thank you for your supportive comment.<br>4) The SRC supports retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts, associated litigation and potential renegotiation of associated operational agreements while supporting FERC’s mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation methodologies is required.<br>Response: Thank you for your supportive comment.<br>MOD-030<br>Several requirements are written with sub-requirements that are really criteria. These sub-requirements should be incorporated directly into the requirement itself. Otherwise, we risk having the Commission assign a VRF to something that really is criteria or explanatory text. Some examples include R2, R3, and R4. R2 could be written as:<br>R2. The TSP shall identify Flowgates for use in the AFC process based on the following minimum criteria.<br>- Flowgates should be defined with contingencies that are used in operations and planning studies for the associated time horizon. |

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| | -At least the first Flowgates identified as limits to transfer from or to all adjacent BA within the TOP transmission system.<br>-Any modeled Flowgate that has been subjected to Interconnection wide congestion management procedure or another TP using methodologies defined by MOD-28 or MOD-29 has requested that meets one of the following two criteria.<br>-Any generator within the Transmission Service Provider area has at least a 5% PTDF or OTDF impact on the Flowgate when delivered to aggregate load in the TSP areas or<br>-A transfer from any BA within the TSP's area to a BA adjacent that has at least a 5% PTDF or OTDF impact on the Flowgate<br>We agree with that the remaining sub-requirements of R2 are really sub-requirements.<br>Response: The standard drafting team has reviewed all of the sub-requirements and has made adjustments where appropriate.<br><br>R4 should be rewritten as because the assumptions should be specifically designed and it is too vague:<br>R4 The Transmission Service Provider shall use contingencies from it planning and operating studies for the applicable Time Horizon and should model the impact of point-to-point Transmission Service as:<br>- When the source or sink are specified in the reservation, the Transmission Service Provider should model the reservation in the following order of importance:<br>1. Model the reservation using the actual source and sink in the model.<br>2. Map to an "equivalence" or<br>3. Map to the interface point with the adjacent upstream Transmission Service Provider as the Source the adjacent downstream Transmission Service Provider as the Sink.<br>- When the source or sink are not specified, the Transmission Service Provider should map the reservation to the interface point with the adjacent upstream Transmission Service Provider as the Source the adjacent downstream Transmission Service Provider as the Sink.<br>Response: The SDT has modified the language to be clearer, and have also allowed for more flexibility by providing for source/sink processing rules to be specified in the ATCID.<br><br>R2.2 should also require a change to flowgates any time there is a topological change that impacts one.<br>Response: The SDT does not believe that this should be a requirement since there are other methods to incorporate the impacts of topological changes. This requirement does not disallow updating flowgates more often or for topological changes.<br><br>The VSLs for R1 need to be defined according to the Violations Severity Levels Development Criteria document. R1 fits the procedure/program category. Lower, Moderate and High VSLs should be defined based on some of the criteria being included.<br>Response: The VSLs have been updated to incorporate two levels. |

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| Response: Please see in-line responses. | |
| Manitoba Hydro | For Standard MOD-030-1, R2.1.2, the phrase "first three limiting" is too prescriptive and should be removed. |
| Response: The requirement could create some unneeded flowgates, but the SDT feels that this is not overly burdensome to those using the flowgate methodology. In order to maintain reliability the SDT believes that the minimum of the first three limiting Elements/Contingency combinations within the Transmission Operator's system being included as Flowgates is required. | |
| MidAmerican Energy Electric Trading | Although the standards are heading in the right direction, two things that must be done are to create an on-the-path, off-the-path methodology for determining which facilities to include when determining an ATC and the standard must create rules on how to include partial path reservations. If these two things are not done in a consistent manner, the entire process falls apart. |
| Response: The drafting team has, for the most part, addressed these items. Regarding on path and off path, ATC in MOD-028 and MOD-030 is based on all potential limits in the model, including off path constraints.<br>Regarding partial path reservations, the drafting team understands the concern expressed, and believes that the methodologies each handle this in different ways. MOD-029 does not include any flow-based analysis, and therefore partial path reservations are irrelevant. MOD-028 addresses this by requiring monthly or longer service include all adjacent TSPs reservations, filtered to eliminate duplicates; for shorter than monthly service, MOD-028 does not include flow-based analysis. MOD-030 includes similar language for all point-to-point reservations (including adjacent). We believe that currently, given the three methodologies, this is the best approach. | |
| Midwest ISO | General comments on MODs:<br>- All Violation Risk Factors in MOD-001, -004, -008, and -030 should be Lower as none represent a risk of cascading outages if they are not met.<br>We agree that none of these requirements represent a risk of cascading outages if they are not met. However, this does not mean that all requirements should be considered “lower.” A requirement with a Violation Risk Factor of Lower is one that “if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.” We believe that there are many requirements in these standards to which this VRF should apply, but there also are many that can have a more significant impact than this.<br>A requirement with a Violation Risk Factor of Medium is one that “if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.” We believe that several of the requirements in these standards, if not met, can directly affect the electrical state or capability of the bulk electric system.<br><br>- Many of the “sub-requirements” listed in the standards should either be bulleted items under the standard or removed and placed in an Appendix, rather than being made actual requirements themselves. For example, in MOD-001, R3, the requirements R3.1 through R3.6 could be just bulleted or placed in an Appendix with R3 reworded to say that the ATCID must address all the items in Appendix xx.<br>Response: Since each of the items listed in R3.1 through R3.7 are required in the ATCID, they should be sub- |

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| | requirements. Bulleted lists are used to indicate items that do not all have to be performed, but may be selected from.<br>MOD-001-1:<br>- MOD-001, R1, should read "…Transmission Operator or Transmission Service Provider…" After hearing some industry comment that including this "or" (as we have in multiple comments) may not be possible in a standards requirement, we look to the team to determine how best to include some flexibility in which entity is required to meet the standard, to respect the varying distribution of work across these regions.<br>Response: The drafting team believes that the functional model indicates this to be the Transmission Operator.<br><br>- In MOD-001-1, R6, the method of notification should include an option for public posting such as OASIS.<br>Response: The intent of this requirement is that the TSP take an action that calls the attention of the listed entities to the fact that the ATCID is changing. Simply posting on OASIS does not meet this intent.<br><br>- MOD-001-1, R10. 14 days can be too short when there are multiple requests pending. There should be a queue process. It is reasonable to request a response time for the first request in the queue, but not on all simultaneous requests.<br>Response: The time has been changed from 14 days to 30 days. Note that providers need not wait to build their data exchange systems until the data is requested; the intent of the 30 days is to allow for any necessary coordination details and access approvals to be taken care of prior to the beginning of the data exchange.<br>- MOD-001-1, R10.12 Since there is a requirement to provide this information in 14 days, this needs to be clarified to say the information that must be provided is the rules for calculating counterflow used in the calculation of ATCs, not the actual MW values themselves. A database of the actual MW values for any given calculation would be extremely large and could not be provided, nor would it serve any real purpose.<br>Response: This requirement has been deleted.<br><br>MOD-004-1:<br>- For Standard MOD-004, R3 and R4, A monthly value is extremely difficult to administrate and implement in the ATC calculation. Such a requirement will subject the TSP to significant increases in cost (the vendor has to provide new code and the frequency of TSP updates would drastically increase). GCIR calculation part has to do a lot more studies. Midwest ISO suggests leaving it to each region to decide on the time intervals.<br>Response: The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. The standard is requiring that entities update their CBM at least once a month to ensure that no unneeded CBM is still being held back from the market. The standard has been clarified that incremental changes OR full recalculation is acceptable.<br><br>- MOD-004, R3.1 – This section should be updated to clarify what is meant to be requested. For example, it states "requested for each month for each year for the next ten year period." Do you really want 120 months worth of requests, or 12 monthly requests and 9 yearly? Suggested wording "for each month for the first 12 months and for |

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| | each year for the remainder of the ten year period"<br>Response: This phrase has been deleted to be clearer.<br><br>- MOD-004, R3.2 – Why should LSE update every month if CBM is only calculated once per year? We suggest that these timelines be clarified.<br>Response: The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. The standard is requiring that entities update their CBM at least once a month to ensure that no unneeded CBM is still being held back from the market. The standard has been clarified that incremental changes OR full recalculation is acceptable.<br>- MOD-004, R9 -- Should be adjusted so that it explicitly states that only the timing requirements for the Real-Time market only will be waived. For example, the Day-Ahead Market timing requirements cannot be waived.<br>Response: The SDT has modified the requirement to incorporate the suggested change.<br>MOD-008-1:<br>- MOD-008, R1.5: "If TRM is zero for any of the time periods listed…"<br>Response: The SDT has rewritten this requirement such that if the provider does not use TRM, they must so indicate.<br>MOD-030-1:<br>- MOD-030-1, change R1 language to affect M1 regarding criteria used by Transmission OwnerR1, TSP should not be responsible for actively notifying changes made to criteria set by TO. Suggested wording is "… shall include … (ATCID) the practice or a link to the practice the TSP uses for adding Flowgates".<br>Response: The Transmission Service Provider is responsible for interacting with the Transmission Operator to ensure this information is available.<br><br>- For Standard MOD-030-1, requirement R.2.1.1. is redundant with the definition of Flowgate given in the "definitions" section. This requirement should be removed, or at least reworded to read "…may be a Flowgate."<br>Response: The drafting team has corrected and clarified this language.<br>- For Standard MOD-030-1, R2.1.2, the phrase "first three limiting" is too prescriptive and should be removed. For example, if the most limiting first contingency transfer is a large value, say 10,000, adding first three limiting elements/contingency combinations is not necessary. If the requirement can't be deleted, we suggest adding wording that sets a transfer level such that the first three constraints that cause the FCITC to fall under that level will be captured. Also, "source sink combinations" needs to be further defined as a calculation entity of any size could have thousands of these possible combinations. Also, if this in-depth study is required, the frequency in R2.2 should be decreased (as this is a minimum standard).<br>Response: The requirement could create some unneeded flowgates, but the SDT feels that this is not overly burdensome to those using the flowgate methodology. In order to maintain reliability the SDT believes that the minimum of the first three limiting Elements/Contingency combinations within the Transmission Operator's system being included as Flowgates is required. The SDT has modified R2.1.1. and R2.1.2 to include the phrase, "up to the path capability". The source sink has been changed to POR POD in R2.1.2. The frequency in R2.2 has been modified to annually. |

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| | - MOD-030-1, R2.3 rating issues, refer to comments from SRC, which says "MOD-030-1, R2.3 does not identify that TFC can be limited by an IROL but it should. If selling transmission service really requires development of a reliability standard, R2.4 should be modified to require updating the TFC any time the underlying determinants, such as facility ratings, change.".<br>Response: Please refer to responses to ISO/RTO Council (IRC).<br>- MOD-030-1, R5.1. This is not always the best practice. For example, while using PSS/E model, some outage remote to the TSP service area can cause the case to not solve and the TSP has to either use DC power flow solution or ignore the outage. The impact from ignoring a remote outage on the accuracy of AFC is much smaller than that from using DC power flow. The TSP has to temporarily block the outage to achieve overall better accuracy. Suggestion wording is "… have been executed, to the extent it helps improve the AFC calculation accuracy." Understanding that the ability to measure deviations may become an issue, the wording could be adjusted to state "… have been executed, except for any outages that, if included, would force the calculation into a less accurate solution technique." We realize that the suggested wording is not perfect, but we're hoping that the team understands our intention and can adjust it accordingly.<br>Response: R5.1 has been revised to provide additional flexibility.<br>- MOD-030-1, R5.2. Should add "to the extent they are available" to the end. Not all MISO third parties have that data available.<br>Response: The requirement says to use any AFC provided. If you are not provided an AFC value, then you do not need to use it, and should use the number you calculated.<br>- In MOD-030-1, R8 and R9, "ATC" should be "AFC".<br>Response: The SDT has corrected this typographical error.<br>- MOD-030-1, R6.3 and 6.4, should say a 3% distribution factor or an impact of 3% of the total MW of the PTP request, not 3% of the distribution factor.<br>Response: The SDT has modified the requirement to incorporate this language, as well as changed the threshold to reference that used in applicable congestion management procedures.<br>- MOD-030-1, R10 should be revised to say "The Transmission Service Provider shall convert or provide a tool to convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths."<br>Response: The standard does not prohibit the use of a tool to convert AFCs and TFCs. |
| Response: Please see in-line responses. | |
| Modesto Irrigation District | MID supports the comments submitted by SMUD on behalf of the WECC MIC MIS ATC Drafting Team as to this inquiry. |
| Response: Please see responses to the WECC MIC MIS ATC Drafting Team. | |
| MRO | |
| New Brunswick System Operator | 1. Since a TTC limit may be due to thermal or stability limit, those limits that are considered IROLs should be required to be identified in the methodology. |

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| | Response: SOLs and IROLs are required to be identified in TOP-002 and monitored in TOP-004. The SDt does not see the need to identify them in the methodology.<br><br>2. If no inputs to an ATC have changed then an update should not be required. (MOD-001)<br>Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation. |
| Response: Please see in-line responses. | |
| NorthWestern Energy (NWMT) | MOD-001-1, A., 3. the stated Purpose contains noble goals which are not required for reliable system operation but for viable commercial activity. Reliable system operations are impacted by incorrect TTC values and uncoordinated transaction scheduling activities.<br>Response: The Drafting Team has clarified in the stated purpose why these standards are required for reliable system operation as follows: To promote the consistent and reliable application and documentation of Available Transfer Capability (ATC) calculations for analysis and system operations.<br><br>MOD-001-1, A., 4. applicability, Transmission Service Provides calculate ATC. Transmission Operators (in the near term) and Transmission Planners (in the longer term) calculate TTC.<br>Response: The SDT agrees that these are good descriptions of the roles entities play in determining ATC and TTC. The SDT does not believe the Transmission Planner should be a applicable entity in the standard, as they are dealing with long-term issues.<br>MOD-001-1, B., R1, Transmission Operators calculate transfer capability (TTC) of facilities within its TO area. Transmission Planners calculate transfer capability (TTC) of facilities within their TP areas. Transmission Service Providers calculate ATC for those paths that they are required to, choose to, or are asked to post.<br>Response: It is unclear what change is being suggested.<br>MOD-001-1, B., R2 is a good requirement, but for commercial reasons, not reliability reasons. Transmission customers need to have access to more “granular” ATC closer to real-time.<br>Response: The SDT believe that calculation of ATC relates to the ability of the Transmission Service provider to understand expected energy flows on both its own system and those systems of other entities for future time periods. Accordingly, the same access to current data has reliability aspects as well as commercial aspects.<br><br>Also, why were weekly ATC values not included?<br>Response: The Drafting Team did not include weekly values because we do not believe they are necessary for reliability nor are they required by the pro-forma Tariff.<br><br>MOD-001-1, B., R3 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability. This requirement to create a separate document creates an undue burden on the industry - transmission customers will have two different documents to review, and transmission service providers will have two different documents to maintain. |

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| | Response: The standard does not preclude entities from creating one document that meets both needs.<br>MOD-001-1, B., R3 the term "Facility" is used several times in MOD-001-1. The NERC glossary says facility is "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)". In R3.3 the requirement to list the Transmission Operators and Planning Coordinators for every facility under the TSP's tariff is burdensome and does not have value. Hundreds of facilities make-up even small systems. R3.3 should say "for each path for which the Transmission Service Provider calculates ATC, list the corresponding Transmission Operator and Transmission Planner and Reliability Coordinator".<br>Response: The Drafting Team has modified the requirement to require a list of Transmission Operators from which the Transmission Service Provider receives data for use in ATC calculations instead of requiring this information for each facility. The Drafting Team could not identify a reason to include the Reliability Coordinator.<br><br>MOD-001-1, B., R3.6 "Allocation methodologies" – it is not clear to what this means? Perhaps the following: "For paths where multiple Transmission Service Providers share capacity or have rights, describe how the capacity is allocated among providers", or words to that effect.<br>Response: The Drafting Team added detail to this requirement to address this concern.<br><br>MOD-001-1, B., R4 is not needed, it is already covered in R3.2. Since R4 leaves it open to each TSP's choice and requires them to document it, perhaps as a suggestion, the requirement could be to have the TSP do as they say they do in their Attachment C. The requirement might be rewritten to say "the TSP utilizes counter schedule information in their firm ATC calculations as specified in their Attachment C." Then, if the TSP fails to document or to do as they say they do, this could be a violation of the requirement.<br>MOD-001-1, B., R5 is not needed, it is already covered in R3.2. Since R4 leaves it open to each TSP's choice and requires them to document it, perhaps as a suggestion, the requirement could be to have the TSP do as they say they do in their Attachment C. The requirement might be rewritten to say "the TSP utilizes counter schedule information in their firm ATC calculations as specified in their Attachment C." Then, if the TSP fails to document or to do as they say they do, this could be a violation of the requirement.<br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>MOD-001-1, B., R6 is not necessary. Revisions to Attachment C are to be filed and posted.<br>Response: These are to be notifications to the entities to alert them to changes that may impact them. Filing and posting does not provide notification.<br><br>MOD-001-1, B., R7 Attachment C is already required to be posted (available) for any entity to review, subject to CEII |

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| | concerns.<br>Response: This requirement is not in conflict with the requirement to post Attachment C.<br><br>MOD-001-1, B., R8 does not read clearly. It can be interpreted as requiring any restudy of TTC to include previously used data rather than data that is reflective of the conditions of the time period being studied. Perhaps the requirement was for data used in the determination of TTC should be the most accurate, up-to-date data available and should reflect the expected conditions of the period of time under study.<br>Response: The requirement says “assumptions”, not “data”. The Drafting Team has added examples of assumptions to the associated measure which should decrease the change of said misinterpretation.<br><br>MOD-001-1, B., R9 is not a reliability concern. In addition, it is unduly burdensome. Current and accurate ATCs are a commercial concern. In addition, performing 168 hourly calculations every hour when neither TTC nor ETC has changed, benefits no one and is costly. The commercial requirement should be to require the recalculation of hourly ATC once a day and whenever either TTC or ETC changes for any period of time between this hour and the next 168 hours. Also, require the recalculation of daily ATC once a day for the next 30 days and whenever either TTC or ETC changes for any period of time between this hour and the next 31 days.<br>Response: The SDT has modified the language to not require recalculations if the components in the ATC equation have not changed. However, the SDT does not agree this is only a commercial requirement. The amount of service sold is based on the amount of energy that can be transferred reliably, and these standards intend to ensure that number is as accurate as possible.<br><br>MOD-001-1, B., R10, this requirement for data sharing between reliability entities is a good concept. However, as currently worded, all the burden to supply data is incorrectly placed totally upon the TSP and not on the Transmission Operator or Transmission Planner. Much of the data listed is critical for proper TTC calculation which the TSP may not have access to. The TSP calculates ATC based on upon TTC supplied by the Transmission Operator and/or Transmission Planner.<br>Response: The Transmission Provider will be responsible for working with their Transmission Operators or Transmission Planners to secure the data.<br><br>This requirement does not specify how the request is made or how the response or provision of data is dated.<br>Response: The SDT believes this to be implementation details to be determined by the Transmission Service Provider and the requestor. NAESB may elect to define standards in this area.<br><br>The corresponding measurement, M9, implies that all data items requested will be supplied within 14 days, but |

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| | requirement states that the TSP will begin to make available at the 14 day mark.<br>Response: M9 measures whether or not the "requested data items" were begun to be made available. By "begun," the standard means that the process of sending all the data was started, not that only some of the data requested was sent.<br><br>In addition, change first sentence words "…days of a request of any Transmission…" to "…days of a request made by any Transmission…" to read more in-line with the intent.<br>Response: The SDT has rewritten this requirement to be clearer.<br><br>Additionally, the requirement borders on a run-on sentence. Suggest moving the list of allowable requesters from R10 to be a sub-requirement R10.xx. The list of data is not all inclusive, there may other information needed. By each item, list what entity would have that data – TSPs would have ATC and ETC information, operators and planners would power flow data, etc.<br>Response: The requirement has been rewritten to improve clarity. The Drafting Team could not identify any other information that would be needed for ATC calculation. It would be difficult to determine for all situations and company organizations who would have the listed data, and the value of identifying that couldn't be determined. The Transmission Service Provider is responsible for supplying the data.<br><br>MOD-004-1, A., Capacity Benefit Margin is a use of the transmission system that is requested by a load serving entity. This standard contains requirements for the interactions between the LSE and the transmission provider. These requirements are largely commercial in nature and should be under NAESB development. Reliability standards concerning CBM should only require LSEs to acquire minimum CBM to ensure service to load.<br>Response: CBM is a margin used to ensure reliability. Not only requests for it, but the actual setting of it and its ultimate inclusion in the ATC calculation all have reliability impacts, and are appropriate for development in this standard.<br><br>MOD-004-1, A., 6. Effective Date language is not but should be exactly the same for all six MOD draft standards.<br>Response: The SDT has modified the language to ensure it is consistent, recognizing that the standards will now be posted for separate ballots.<br><br>MOD-004-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider's CBM methodology. This requirement to create a separate document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and providers would have to maintain two different documents. |

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| | Response: The standard does not preclude a Transmission Service Provide from using one document to meet both requirements. Note that the Attachment C may not be as detailed as the implementation documents, however.<br><br>MOD-004-1, B., R2 is not necessary. Revisions to Attachment C are to be filed and posted (available) for any entity to review, subject to CEII concerns.<br>Response: R2 is intended to ensure this information is provided to reliability entities for reliability purposes, regardless of what other information is required to be posted to meet FERC requirements.<br><br>MOD-004-1, B., combine R3.3 language into R3.1.<br>Response: The SDT does not understand the reason to combine these requirements.<br><br>MOD-004-1, B., R3.2 it seems more reasonable for the requirement to read “LSE shall review any active CBM requests at least every six months and submit updates as required.”<br>Response: The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. The Standard is requiring that entities update their CBM at least once a month to ensure that no unneeded CBM is still being held back from the market. The standard has been modified to clarify that incremental changes are allowed without entire re-calculation.<br><br>MOD-004-1, B., R4 uses active verb “shall set….as follows:” but R4.1 says “Determine the amount of CBM…”. To align the language a little better perhaps R4 should simply say “…the Transmission Service Provider shall:”. In that way the TSP shall “determine” (R4.1), shall “set” (R4.2), shall “increase” (R4.3).<br>Response: The drafting team believes the standard as now written is correct.<br><br>MOD-004-1, B., R4.3 contemplates the case where there is insufficient capacity to meet all the CBM requests on a particular path, but there is no discussion on allocation of limited capacity to the requests. Is NAESB working on this aspect? If not, is it a TSP’s discretion to develop a CBM allocation methodology?<br>Response: Since CBM is a margin, and not a reservation, there is no need to allocate. The only time this would be required would be if multiple entities who requested CBM needed CBM at the same time, and at that time, their use would need to be pro-rata adjusted (possibly through TLR or other interconnection-wide congestion management procedures). Otherwise, available CBM might be withheld from use unintentionally.<br><br>MOD-004-1, B., R8, R9, R10, M11, M12, M13 use of the terms "tag" or "Interchange Transaction Tag" which is inconsistent with NERC INT and NAESB CI BP standards where specific reference to “tag” or “e-Tag” has purposefully |

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| | been avoided in those standards. The term Request For Interchange (RFI) refers to a collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink BA. Or the term Arranged Interchange refers to The state where the Interchange Authority has received the Interchange information (initial or revised) and has distributed that information for reliability assessment. I believe that in these requirements, Arranged Interchange is the more appropriate language.<br>Response: The drafting team has modified the standard to use the term Arranged Interchange.<br><br>MOD-004-1, B., R10 requires, without exception, that all submitted Arranged Interchange using CBM must be approved. This would force TSPs to potentially approve malformed transactions possibly citing incorrect contract arrangements, incorrect connectivity, etc. Perhaps the requirement could state the TSP shall approve all valid requests to schedule CBM. The drafting team might consider requiring the TSP or other approval entities to supply a valid reason for denying a CBM schedule.<br>Response: We believe that in a capacity emergency, an import of the energy is more important that ensuring the details of assignment refs and the like are correct. Note that Balancing Authorities are not prohibited from denying the Arranged Interchange; this is dealing solely with the Transmission Service Provider.<br><br>MOD-008-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider's TRM methodology. This requirement to create a separate document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and TSPs two different documents to maintain.<br>Response: The standard does not preclude a Transmission Service Provide from using one document to meet both requirements.<br><br>MOD-008-1, B., R1.1 suggest modifying to read: "For each path or flowgate that ATC or AFC is calculated, describe how each of the following components of uncertainty are used in calculating TRM for each of the ATC time horizons (if not applicable, indicate as such):" The words "ATC time horizons" could be used to eliminate the need for R1.4.<br>Response: The drafting team intentionally avoided the use of the phrase "time horizons" in order to avoid confusion with NERC Compliance Time Horizons.<br><br>MOD-008-1, B., R.3 what "request" is being referred to? Should it read "…seven calendar days of a request from:"? Or should "of a request" be removed as a typo?<br>Response: The team reviewed this requirement. Based on your comments and others the team made several changes that should address your concerns:<br>#1: R4 on the TSP was removed, it did not make sense for the TSP to serve as aggregator for the Transmission Operators material and would be burdensome on some TSP to have to respond to requests for information that is not theirs.<br>#2: R3 was modified to say make available instead of provide to better reflect the phrasing in other standards and to indicate that shipment of the material is not required, a posting such as a secure FTP site could be sufficient. |

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| | #3: R3 was modified to require a response to the requestor with the material requested, not a blanket response to all parties listed.<br>#4: R3 was modified to allow for 30 days instead of 7 days. While the material should be readily available, it is more common to allow 30 days for non critical information transmittal and this resolves the concern at some smaller entities over holidays and vacations.<br>#5: Due to the elimination of R4, R3's list of possible requestors was expanded.<br><br>MOD-008-1, B., it seems that R1, 2, and 5 could be merged together into a new R1 TRM calculation and documentation. R3 and 4 could merged together into a new R2 on TRM data sharing.<br>Response: While we agree these items could be merged, we believe it is more appropriate at this time to keep them as separate requirements.<br><br>MOD-029-1 inclusion of the Rated System Path methodology is greatly needed and appreciated. The drafting team was wise in including it and should be thanked for their efforts.<br>Response: Thank you for your supportive comment.<br><br>MOD-029-1 suggest reordering R4 to be R1.<br>Response: The SDT has reordered R3 and 4 to address this comment.<br><br>MOD-029-1 R1 (modeling requirements) should include the statement that the data listed below should reflect the expected conditions for the applicable time period.<br>Response: The drafting team agrees and has modified R1 to address your concerns.<br><br>MOD-029-1 R1.6 change "peak load forecast" to "applicable load forecast" since some SOLs, and ultimately TTCs, may be based upon light load conditions.<br>Response: The SDT has eliminated the word "peak" from the requirement.<br><br>MOD-029-1 delete R2.7 as it, in its current form, does not provide the entire paradigm contained in the WECC's Procedures For Regional Planning Project Review And Rating Transmission Facilities.<br>Response: The SDT believes this is covered in section 3 of the WECC PCC handbook.<br><br>MOD-029-1 in R6, is the "non-firm capacity reserved for NITS" the same as Secondary Network Service (i.e., NN-6)?<br>Response: It is the same as Secondary Service and the requirement has been revised to reflect that.<br><br>MOD-029-1 in R7 & R8, what are "Postbacks"? This term is not used in the west.<br>Response: This term came from Order 890; to the drafting team's knowledge, it has generally not been used in the |

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| | East or ERCOT either. The SDT believes that postbacks are used in the West (e.g. release of unscheduled firm as non-firm ATC), but are not referred to in this fashion. The SDT has clarified the term post back by incorporating the following definition: “Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.” Note that NAESB will be defining specifically what values should be considered when determining Postbacks.<br><br>MOD-029-1 in R5, R6, R7, & R8, calculation of ETC and ATC are commercial concerns and should be addressed in business practice standards NAESB and enforced through FERC’s adoption of those business practice standards into the CFR.<br>Response: The drafting team does not believe these are only commercial concerns. If calculated correctly, ATC should be a reasonable approximation of what flows are expected on the system at a given point in time. Ensuring that this number is accurate will help ensure that entities do not oversell their systems into overloads.<br><br>MOD-029-1 in R8 the requirement says we are to use the same formula for all horizons – this is incorrect. For the real-time, same-day time frame, we release all unscheduled capacity as non-firm ATC. As such, the formula would read:<br>ATCNF = TTC – Scheduled ETCF – Scheduled ETCNF – CBMS – TRMU + Counter-schedulesF + Counter-schedulesNF<br>Response: It is the SDT’s understanding that NAESB will incorporate unscheduled capacity in postbacks. The SDT has clarified the term post back by incorporating the following definition: “Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.” Note that NAESB will be defining specifically what values should be considered when determining Postbacks. Therefore, the requirement is correct as written.<br><br>MOD-029-1 in R8 the ETCF definition should be changed from "…existing non-firm commitments…" to "…existing non-firm commitments…"<br>Response: The SDT has corrected this typographical error.<br><br>MOD-030-1 it is unreasonable for TSPs to convert AFC values into ATC values simply because FERC regulations fail to contain the term AFC. For large systems using this methodology, posting thousands of ATC values benefits no one if AFC values can give transmission customers a better picture of available capability of the transmission system.<br>Response: The SDT has modified the standard such that it does not require this conversion, but requires that if the conversion is done, it be done as described. |
| Response: | |
| NPCC Regional Standards Committee | MOD-001<br>1.R1: While in many cases, the decision on which ATC methodology to use may be made jointly between the TSP and TOP. However, since you cannot have joint responsibility in the standard, the TOP is the appropriate Functional Model entity.<br>Response: The SDT concurs with your assessment. |

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| | Acronyms TSP, and TOP need to be defined in the Background Information on p. 3.<br>Response: These are defined in the glossary; the background was not intended to be part of the standards.<br><br>2.R8: Since this standard deals with short-term Transmission Service, the reference to planning studies should be removed from R8<br>Response: While this standard deals with short-term service, it requires that assumptions used in that short-term analysis are consistent with those used in the long term. The SDT does not believe this to be in conflict.<br><br>3. R8 is an appropriate representation of the broad FERC requirement as-written that will force entities to make a conscious effort to ensure this consistency occurs. While the language is somewhat vague, we recognize that adding more detail would be unreasonably difficult. We would suggest that detail be added in the measures to provide examples of what a valid demonstration would be. For example, TOP/TSP may provide evidence to demonstrate that the source of the inputs used in the operational studies is the same as for the TTC/ATC studies.<br>Response: The Drafting Team could not develop a comprehensive, exclusive list of assumptions, but has added a partial list of examples in the measure, M6.<br>4.<br>TOP and TSP need to be defined in the Background Information on p. 3.<br>Response: These are defined in the glossary; the background was not intended to be part of the standards.<br><br>MOD-028<br>1. R8 should be broken down into the different timeframes; sending TTC values used in hourly and daily ATC calculations seven days after being calculated is too late. Suggest: 8.1 within one calendar day of its determination for TTCs used in hourly and daily ATC calculations; 8.2 within seven calendar day of its determination for TTCs used in monthly ATC calculations.<br><br>Response: The SDT has modified the standard to incorporate the suggested change. The following modifications were made:<br>R8.1.One calendar day of its determination for TTCs used in hourly and daily ATC calculations<br>R8.2. Seven calendar day of its determination for TTCs used in monthly ATC calculations.<br><br>MOD-030<br>1. R4 seems duplicative of MOD-001 R8<br>Response: The Standard Drafting Team agrees. R4 has been edited to remove this duplication.<br>2. R6.3, 6.4 - The last sentence of R6.3 seems to belong in 6.4 not 6.3<br>Response: The SDT has corrected this typographical error. |

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| Response: Please see in-line responses. | |
| NYISO | The NYISO joins in and supports the comments submitted by the IRC in response to this question. The NYISO also supports the comments submitted by the NPCC.<br>NERC's November 21 filing with FERC for an extension of time to complete the ATC standards development process described MOD-29 as a methodology used "exclusively" in the Western Interconnection. It also referred to MOD-28 as a methodology used "primarily" in the Southeast. Notwithstanding these descriptions, the NYISO is not aware of any NERC proposal to restrict the use of MOD-028 or MOD-29 to particular geographic regions. If, however, it is NERC's intent to impose such restrictions, the NYISO respectfully requests that NERC reconsider. Order No. 890 did not impose geographic restrictions or require all transmission providers in a given region to use the same methodology. Transmission Providers should be free to implement whichever methodology best suits them, their customers, and the needs of any markets they administer, so long as they comply with that methodology's requirements.<br>Response: Any such restriction would have to be included in the standard and go through the full NERC process. The SDT has no intention of doing so at this time.<br><br>With respect to MOD-028, NERC should revise requirements R3 and R4 so that transmission providers are not required to re-calculate and re-post TTC at the specified intervals at times when none of the underlying inputs to the TTC calculation have changed. Under the NYISO system, TTC values do not change often. Accordingly, having to make more frequent TTC calculations would require the NYISO to adopt costly compliance measures that offer no benefit to its customers.<br>Response: R6 describes how often the Transmission Operator should perform the calculation. Depending on the timeframe of the TTC being calculated, R3 and R4 describes the appropriate data for the period that is being calculated. We have modified R6.1 as follows:<br>"R6.1. At least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations."<br><br>With respect to MOD-029, NERC should revise requirements R2.3 and R2.6 or, in the alternative, clarify in response to this comment that they do not apply to transmission providers, such as the NYISO, that do not offer physical transmission rights based on contract-path reservations.<br>Response: If you do not have posted paths limited by contract or situations where multiple ownerships of Transmission rights exist on a ATC Path, then these requirements would not apply.<br><br>Similarly, with respect to MOD-001, NERC should revise requirements R10.3 through R10.8, and R10.14, or in the alternative, clarify in response to this comment that they do not apply to transmission providers, such as the NYISO, that use financial reservation models and thus will not have the information that the proposed requirements direct them to make available on request. Otherwise, the R.10 information requirements would effectively call on the NYISO to perform functions that FERC's waiver orders excuse it from performing and that would serve no purpose under the NYISO model.<br>More specifically: |

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| | R10.3 -- Unit Commitments and Dispatch Orders -- Under the NYISO system, this information is only available for the day-ahead and real-time market horizons. The NYISO will not have this information for the "operations planning" horizon as the proposed language would require.<br>Response: This requirement is intended to allow other transmission providers to estimate flows expected from the dispatch of generation within the NYISO. The SDT assumes that assumptions of some kind with regard to dispatch order are used in your planning studies. Providing this information will meet the requirements of the standard.<br><br>R10.4 -- Firm and Non-Firm Network Integration Transmission Service details -- The NYISO's OATT currently requires the NYISO to offer a "financial" version of this service but no customer has ever requested it. The NYISO anticipates that it will propose to FERC that the Network Integration Transmission Service provisions of its OATT be eliminated well before MOD-001 is implemented. The NYISO will therefore not have any information on such reservations to make available in response to requests under R10.<br>Response: The SDT understands your situation and believe this to be acceptable.<br>R10.5 -- Confirmed firm and non-firm Transmission reservations -- In the NYISO system, customers do not make express, physical firm or non-firm transmission reservations. The NYISO will, therefore, not have any information on such reservations to make available in response to requests under R10.<br>Response: The SDT understands your situation and believe this to be acceptable.<br>R10.6 -- Grandfathered firm and non-firm contracted transmission capacity on an aggregated basis -- Although the NYISO honors the grandfathered transmission arrangements that are listed in Attachment L to its OATT it does not make express physical transmission reservations in connection with them. The NYISO will, therefore, not have any aggregated information on grandfathered capacity reservations to make available in response to requests under R10.<br>Response: The SDT understands your situation and believe this to be acceptable.<br>R10.7 -- Firm Roll Over Rights -- The NYISO's FERC-approved OATT has never included the pro forma OATT's roll-over right provisions. The NYISO will, therefore, not have any information on such rights to make available in response to requests under R10.<br>Response: The SDT understands your situation and believe this to be acceptable.<br>R10.8 -- Firm and Non-Firm Adjustments to Reflect Parallel Path Impacts -- Because the NYISO does not support physical firm or non-firm reservations, it has no procedures for gauging their parallel path impacts and will, therefore, not have information to make available in response to requests under R10.<br>Response: The SDT understands your situation and believe this to be acceptable.<br>R10.14 -- Flowgate values - The NYISO does not utilize any flowgates. The NYISO will, therefore, not have any flowgate-related information to make available in response to requests.<br>Response: The SDT understands your situation and believe this to be acceptable.<br>Except to the extent that they are addressed by the IRC or NPCC, the NYISO has no comments on MOD-004 or MOD-008. The NYISO has never set aside transmission capacity for CBM and does not intend to do so in the future. Consistent with NERC's expectation, the NYISO would explain this practice to the extent required in its ATCID. Likewise, the NYISO uses TRM and intends to comply with all of NERC's requirements related to it.<br>Response: The requirement only applies to flowgates used when selling service, so having no values here is acceptable. |

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| | Thank you very much for your attention to these comments. |
| Response: Please see in-line responses. | |
| PacifiCorp | PacifiCorp supports the following general and affirmative comments related to MOD-01 and MOD-029 submitted by the WECC MIC MIS ATC Drafting Team December 14, 2007.<br>GENERAL<br>1) Supports retention of the three methods recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028).<br>2) Strongly supports the retention of the proposed one-year implementation period.<br>3) Supports allowing NAESB to address all “posting” issues as they directly affect OASIS.<br>In addition, PacifiCorp suggests that any standards set forth herein be subject to an acknowledgement by NERC that compliance should not be required until the related NAESB standards are complete.<br>Response: The SDT has discussed this, and believes that compliance with the NERC standards can be accomplished without the associated NAESB standards.<br>MOD-001 UMBRELLA<br>1) Supports allowing the use of more than one methodology for calculation of ATC by any one entity.<br>2) Supports allowing each entity to specify in its ATCID how it will treat counterflows / schedules. (R4., R5.)<br>3) Supports the aggregation of transmission capacity for grandfathered contracts when shared with neighboring requestors.<br>4) Supports the specifically limited universe of entities to which data sharing is required as prescribed in R10.<br>MOD-029 RATED SYSTEM PATH TTC, ETC & ATC<br>1) Strongly supports retention of the requirement(s) in R2.2 that accommodate paths which are “flow limited” by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing practices without re-inventing the wheel where no such effort is required to meet FERC’s goals of transparency and consistency.<br>2) Strongly supports retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.<br>3) Strongly supports the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.<br>4) Supports retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts, associated litigation and potential renegotiation of associated operational agreements while supporting FERC’s mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation methodologies is required.<br>5) Supports the adoption of a definition for counterflow to clarify its application in each equation. In addition PacifiCorp echoes its earlier comment in Section 2 that any changes to clarify the term counterflow should not undermine the flexibility allowed in the definition of the term "counter-schedules" in MOD-029.<br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and |

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| | we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules. |
| Response: Thank you for your supportive comments. Please see in-line responses. | |
| PJM Interconnection LLC | PJM encourages further development that would include a diversity of implementations. PJM also wishes a clear distinction between reliability aspects and economic aspects in further revisions<br>MOD-001 Available Transfer Capability<br>R3.2 - Is this requirement consistent with use of the terms "counter flow" and "counter reservation" in the rest of the Standard?<br>Response: The drafting team believes that it is.<br><br>R3.6 - What is the definition of "Allocation methodologies" and is it different for flowgate capabilities or paths?<br>Response: The Drafting Team added detail to this requirement to clarify what the intent is.<br><br>R9: We believe the frequency could be better addressed and aligned with other posting requirements by NAESB in business practices.<br>Response: These requirements only apply to the minimum calculation times. Posting times remain in the purview of NAESB. The Drafting Team has modified the standard to require that the ATC shall be recalculated when a variable in the ATC equation changes, instead of making the requirement time based. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation. M8 has been revised to measure recalculation of AFC and M9 has been revised to measure whether or not ATC has been recalculated when any of the variables have changed.<br><br>R10: Insert "its own data" in the first sentence, 3rd line as follows: …Provider shall begin to make "its own data" available on the schedule specified…<br>Response: The addition has been made as requested.<br>MOD-004 Capacity Benefit Margin<br>R2: The acronym "CBID" in the 2nd line of the first sentence should be "CBMID".<br>Response: The SDT has corrected this typographical error.<br>Entities should have a more reasonable time frame of fourteen (14) calendar days to make CBMID and any changes available to applicable parties.<br>Response: The drafting team has changed the standard to require that the document be provided prior to |

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| | implementing any change.<br>R6 - Fourteen (14) calendar days for providing requested CBM information would be more reasonable.<br>Response: the drafting team believes that five days is adequate.<br>R7.1 and R7.2 - Fourteen calendar days for providing CBM supporting data would be more reasonable.<br>Response: The drafting team has modified the standard to allow 30 days.<br>R9: Add "within the bounds of reliable operation" to the end of the R9 requirement description.<br>Response: The SDT has incorporated the suggested language into the requirement.<br>MOD-008 TRM Calculation Methodology<br>R3, R4, R5 - Fourteen calendar days for providing TRM calculations and supporting data would be more reasonable.<br>(Response for R3, R4) The team reviewed this requirement. Based on your comments and others the team made several changes that should address your concerns:<br>#1: R4 on the TSP was removed, it did not make sense for the TSP to serve as aggregator for the Transmission Operators material and would be burdensome on some TSP to have to respond to requests for information that is not theirs.<br>#2: R3 was modified to say make available instead of provide to better reflect the phrasing in other standards and to indicate that shipment of the material is not required, a posting such as a secure FTP site could be sufficient.<br>#3: R3 was modified to require a response to the requestor with the material requested, not a blanket response to all parties listed.<br>#4: R3 was modified to allow for 30 days instead of 7 days. While the material should be readily available, it is more common to allow 30 days for non critical information transmittal and this resolves the concern at some smaller entities over holidays and vacations.<br>#5: Due to the elimination of R4, R3's list of possible requestors was expanded.<br><br>(Response for R5) Providing the TRM calculation to the TSP is considered by the team to be an important step. In the teams opinion this value should be sent to the TSP's and transmission planners as soon as it is prepared and adopted by the transmission operator. However "as soon as" is not an auditable requirement. The team did not want to require transmission of the value prior to adoption, so settled on a 7 day time frame as reasonable and practical from an evidence standpoint.<br><br>MOD-030 Flowgate Methodology<br>R2.1.1 - The current definition makes every facility a flowgate. Suggest changing the wording as follows, "Any facility within the Transmission Operator's area based on thermal, stability or voltage limits is eligible to become a flowgate." The requirements that follow (R2.1.2 and R2.1.3) would be sub-requirements of R2.1.1 that would be used to determine the subset of all transmission facilities described in R2.1.1 that become flowgates.<br>Response: The Standards Drafting Team (SDT) has modified the language of this requirement to limit the scope.<br>R2.1.2.1 - "This requirement is only applicable if the planning studies and operating studies use the same methodologies. If the planning studies use a TTC methodology then all transmission facilities may be contingencies. In AFC studies only the select flowgate definitions that contain contingency elements would be included. |

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| | Recommend removing this requirement." If this requirement remains suggest following wording, ...Use Contingencies consistent with the Contingencies used in operations studies and planning studies for the applicable time", but not all contingencies used in studies need to be included in transfer analyses."<br>Response: The SDT has modified this to require consistent consistency assumptions, rather than contingencies. The language also now includes the phrase "for the applicable time periods".<br>R2.2 - Should be yearly instead of quarterly. Delete the word "definitions" from the sentence.<br>Response: The SDT changed the requirement to annually for internal flowgates and monthly for external flowgates. The word "definitions" has been deleted from the sentence.<br>R3.1 - Recommend that R3.1 be deleted since TFC may be derived from another source such as a flowgate parameter files. This is should be an acceptable practice since it is easier to maintain flowgate attributes/parameters in files included in the calculation process than in the load flow models.<br>Response: R3.1 does not preclude you from using flowgate parameter files.<br>R3.4 and R3.5 - Change Reliability Coordinator's area to Transmission Operator's area.<br>Response: The SDT feels that requiring the model to contain the facilities in the RC area will be required for consistent, reliable calculation of AFC. The standard drafting team feels that it will not be burdensome to supply such data even for a small TOP within a large RC. The team has added a statement saying, "Equivalent representation of radial lines and facilities161kV or below is allowed." which should help with the modeling.<br>R4.2 - What is the definition of an interface point? It is suggested that the words "the interface point with" should be clarified or revised from the language in bullet points 3,4,7 and 8 under R4.2.<br>Response: The SDT has eliminated the use of the phrase interface point.<br>R5.1 - Recommend rewording of R5.1 to address outage rules. Outage rules used in the standard to define the set of outages to include in monthly or daily calculations where multiple outage periods exist. An example would be that in monthly AFC calculations all outages for the month are not included. Only the set of outages that meet the outage rules (for example all EHV with a duration of greater than 7 days or all outages that occur on the 3rd Wed of the month, etc) The requirement should be reworded to say "all outages that meet the outage rules as specified in the ATCID".<br>Response: R5 has been revised to provide additional flexibility, and entities are required to describe the rules for handling outages during the ATC process in their ATCID.<br>R5.2 - Replace the existing wording and deleting word "any" with the following: "For external third party flowgates, PDF greater than 5% and passing coordination agreement study process, if applicable, use the AFC for each specific flowgate provided by that third party as the AFC for that flowgate, except where there is a mutually agreed temporary problem with that value."<br>Response: The SDT does not believe specifying coordination agreement study processes is with the drafting teams' scope.<br>R6.3 and R6.4 - The threshold values for calculating impacts should be consistent with the threshold values contained in MOD-028.<br>Response: The drafting team has discussed the distribution factors extensively and set them to appropriate levels.<br>R7.2 and R7.4 - The threshold values for calculating impacts should be consistent with the threshold values contained in MOD-028. |

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| | Response: The drafting team has discussed the distribution factors extensively and set them to appropriate levels.<br>R8 - What is a "postback" as defined by NAESB?<br>The SDT has clarified the term post back by incorporating the following definition: “Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.” Note that NAESB will be defining specifically what values should be considered when determining Postbacks. |
| Response: Please see in-line responses. | |
| Progress Energy, Carolinas | |
| Public Service Commission of SC | None. |
| Public Utility District #2 of Grant County, Washington | 1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.<br><br>Please see responses to the WECC MIC MIS ATC Drafting Team.<br><br>2) In reference to MOD-030-1/R10, the requirement should be altered as follows: “The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC’s for its network and provides a tool for AFC-to-ATC conversion (in BPA’s case, Power Utilization Factor Calculators). We believe at this time that this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.<br>Response: The standards do not preclude the use of a tool to create ATCs from AFCs; nor do they require the posting of ATCs. |
| Response: Please see in-line responses. | |
| Puget Sound Energy | MOD-001-1, A., 3. the stated Purpose contains noble goals which are not required for reliable system operation but for viable commercial activity. Reliable system operations are impacted by incorrect TTC values and uncoordinated transaction scheduling activities.<br>Response: The Drafting Team has clarified in the stated purpose why these standards are required for reliable system operation as follows: To promote the consistent and reliable application and documentation of Available Transfer Capability (ATC) calculations for analysis and system operations.<br><br>MOD-001-1, A., 4. applicability, the Transmission Service Provides calculate ATC. Transmission Operators (in the near term) and Transmission Planners (in the longer term) calculate TTC.<br>Response: The SDT agrees that these are good descriptions of the roles entities play in determining ATC and TTC. The SDT does not believe the Transmission Planner should be a applicable entity in the standard, as they are dealing with long-term issues. |

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| | MOD-001-1, B., R1, Transmission Operators calculate transfer capability (TTC) of facilities within its TO area. Transmission Planners calculate transfer capability (TTC) of facilities within their TP areas. Transmission Service Providers calculate ATC for those paths that they are required to, choose to, or are asked to post.<br>Response: It is unclear what change is being suggested.<br><br>MOD-001-1, B., R2 is a good requirement, but for commercial reasons, not reliability reasons. Transmission customers need to have access to more "granular" ATC closer to real-time.<br>Response: The SDT believe that calculation of ATC relates to the ability of the Transmission Service provider to understand expected energy flows on both its own system and those systems of other entities for future time periods. Accordingly, the same access to current data has reliability aspects as well as commercial aspects.<br><br>Also, why were weekly ATC values not included?<br>Response: The Drafting Team did not include weekly values because we do not believe they are necessary for reliability nor are they required by the pro-forma Tariff.<br><br>MOD-001-1, B., R3 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability. This requirement to create a separate implementation document creates an undue burden on the industry - transmission customers will have two different documents to review, and transmission service providers will have two different documents to maintain.<br>Response: The standard does not preclude entities from creating one document that meets both needs.<br><br>MOD-001-1, B., R3 the term "Facility" is used several times in MOD-001-1. The NERC glossary says facility is "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)". In R3.3 the requirement to list the Transmission Operators and Planning Coordinators for every facility under the TSP's tariff is burdensome and does not have value. Hundreds of facilities make-up even small systems. R3.3 should say "for each path for which the Transmission Service Provider calculates ATC, list the corresponding Transmission Operator and Transmission Planner and Reliability Coordinator".<br>Response: The Drafting Team has modified the requirement to require a list of Transmission Operators from which the Transmission Service Provider receives data for use in ATC calculations instead of requiring this information for each facility. The Drafting Team could not identify a reason to include the Reliability Coordinator.<br><br>MOD-001-1, B., R3.6 "Allocation methodologies" – it is not clear to what this means? Perhaps the following: "For |

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| | paths where multiple Transmission Service Providers share capacity or have rights, describe how the capacity is allocated among providers", or words to that effect.<br>Response: The Drafting Team added detail to this requirement to address this concern.<br><br>MOD-001-1, B., R4 is not needed, it is already covered in R3.2. If the drafting team wants to keep it, please move it MOD-028, MOD-029, and MOD-030. Since R4 leaves it open to each TSP's choice and requires them to document it, perhaps as a suggestion, the requirement could be to have the TSP do as they say they do in their Attachment C. The requirement might be rewritten to say "the TSP utilizes counter schedule information in their firm ATC calculations as specified in their Attachment C." Then, if the TSP fails to document or to do as they say they do, this could be a violation of the requirement.<br><br>MOD-001-1, B., R5 is not needed, it is already covered in R3.2. If the drafting team wants to keep it, please move it MOD-028, MOD-029, and MOD-030. Since R4 leaves it open to each TSP's choice and requires them to document it, perhaps as a suggestion, the requirement could be to have the TSP do as they say they do in their Attachment C. The requirement might be rewritten to say "the TSP utilizes counter schedule information in their firm ATC calculations as specified in their Attachment C." Then, if the TSP fails to document or to do as they say they do, this could be a violation of the requirement.<br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>MOD-001-1, B., R6 is not necessary. Revisions to Attachment C are to be filed and posted.<br>Response: These are to be notifications to the entities to alert them to changes that may impact them. Filing and posting does not provide notification.<br><br>MOD-001-1, B., R7 Attachment C is already required to be posted (available) for any entity to review, subject to CEII concerns.<br>Response: This requirement is not in conflict with the requirement to post Attachment C.<br><br>MOD-001-1, B., R8 does not read clearly. Perhaps the phrase "categories of data" could be used. As R8 reads now, it can be interpreted as requiring any restudy of TTC to include previously used data rather than data that is reflective of the conditions of the time period being studied. Perhaps the requirement was for data used in the determination of TTC should be the most accurate, up-to-date data available and should reflect the expected |

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| | conditions of the period of time under study.<br>Response: The requirement says "assumptions", not "data". The Drafting Team has added examples of assumptions to the associated measure which should decrease the change of said misinterpretation.<br><br>MOD-001-1, B., R9 is not a reliability concern. In addition, it is unduly burdensome. Current and accurate ATCs are a commercial concern. In addition, performing 168 hourly calculations every hour when neither TTC nor ETC has changed, benefits no one and is costly. The commercial requirement should be to require the recalculation of hourly ATC once a day and whenever either TTC or ETC changes for any period of time between this hour and the next 168 hours. Also, require the recalculation of daily ATC once a day for the next 30 days and whenever either TTC or ETC changes for any period of time between this hour and the next 31 days.<br>Response: The SDT has modified the language to not require recalculations if the components in the ATC equation have not changed. However, the SDT does not agree this is only a commercial requirement. The amount of service sold is based on the amount of energy that can be transferred reliably, and these standards intend to ensure that number is as accurate as possible.<br><br>MOD-001-1, B., R10, this requirement for data sharing between reliability entities is a good concept. However, as currently worded, all the burden to supply data is incorrectly placed totally upon the TSP and not on the Transmission Operator or Transmission Planner. Much of the data listed is critical for proper TTC calculation which the TSP may not have access to. The TSP calculates ATC based on upon TTC supplied by the Transmission Operator and/or Transmission Planner.<br>Response: The Transmission Provider will be responsible for working with their Transmission Operators or Transmission Planners to secure the data.<br><br>This requirement does not specify how the request is made or how the response or provision of data is dated.<br>Response: The SDT believes this to be implementation details to be determined by the Transmission Service Provider and the requestor. NAESB may elect to define standards in this area.<br><br>The corresponding measurement, M9, implies that all data items requested will be supplied within 14 days, but requirement states that the TSP will begin to make available at the 14 day mark.<br>Response: M9 measures whether or not the "requested data items" were begun to be made available. By "begun," the standard means that the process of sending all the data was started, not that only some of the data requested was sent.<br><br>In addition, change first sentence words "…days of a request of any Transmission…" to "…days of a request made by any Transmission…" to read more in-line with the intent.<br>Response: The SDT has rewritten this requirement to be clearer. |

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| | Additionally, the requirement borders on a run-on sentence. Suggest moving the list of allowable requesters from R10 to be a sub-requirement R10.xx. The list of data is not all inclusive, there may other information needed. By each item, list what entity would have that data – TSPs would have ATC and ETC information, operators and planners would power flow data, etc.<br>Response: The requirement has been rewritten to improve clarity. The Drafting Team could not identify any other information that would be needed for ATC calculation. It would be difficult to determine for all situations and company organizations who would have the listed data, and the value of identifying that couldn't be determined. The Transmission Service Provider is responsible for supplying the data.<br><br>MOD-004-1, A., Capacity Benefit Margin is a use of the transmission system that is requested by a load serving entity. This standard contains requirements for the interactions between the LSE and the transmission provider. These requirements are largely commercial in nature and should be under NAESB development. Reliability standards concerning CBM should only require LSEs to acquire a minimum CBM to ensure service to load.<br>Response: CBM is a margin used to ensure reliability. Not only requests for it, but the actual setting of it and its ultimate inclusion in the ATC calculation all have reliability impacts, and are appropriate for development in this standard.<br><br>MOD-004-1, A., 6. Effective Date language is not but should be exactly the same for all six MOD draft standards.<br>Response: The SDT has modified the language to ensure it is consistent, recognizing that the standards will now be posted for separate ballots.<br><br>MOD-004-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider's CBM methodology. This requirement to create a separate implementation document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and providers would have to maintain two different documents.<br>Response: The standard does not preclude a Transmission Service Provide from using one document to meet both requirements. Note that the Attachment C may not be as detailed as the implementation documents, however.<br><br>MOD-004-1, B., R2 is not necessary. Revisions to Attachment C are to be filed and posted (available) for any entity to review, subject to CEII concerns.<br>Response: R2 is intended to ensure this information is provided to reliability entities for reliability purposes, regardless of what other information is required to be posted to meet FERC requirements.<br><br>MOD-004-1, B., combine R3.3 language into R3.1.<br>Response: The SDT does not understand the reason to combine these requirements.<br>MOD-004-1, B., R3.2 it seems more reasonable for the requirement to read "LSE shall review any active CBM requests at least every six months and submit updates as required." |

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| | Response: The intent of this requirement is to avoid unintentional hoarding. CBM, by virtue of it being a margin, can remove significant amounts of ATC from the market. The Standard is requiring that entities update their CBM at least once a month to ensure that no unneeded CBM is still being held back from the market. The standard has been modified to clarify that incremental changes are allowed without entire re-calculation.<br><br>MOD-004-1, B., R4 uses active verb "shall set….as follows:" but R4.1 says "Determine the amount of CBM…". To align the language a little better perhaps R4 should simply say "…the Transmission Service Provider shall:". In that way the TSP shall "determine" (R4.1), shall "set" (R4.2), shall "increase" (R4.3).<br>Response: The drafting team believes the standard as now written is correct.<br><br>MOD-004-1, B., R4.3 contemplates the case where there is insufficient capacity to meet all the CBM requests on a particular path, but there is no discussion on allocation of limited capacity to the requests. Is NAESB working on this aspect? If not, is it a TSP's discretion to develop a CBM allocation methodology?<br>Response: Since CBM is a margin, and not a reservation, there is no need to allocate. The only time this would be required would be if multiple entities who requested CBM needed CBM at the same time, and at that time, their use would need to be pro-rata adjusted (possibly through TLR or other interconnection-wide congestion management procedures). Otherwise, available CBM might be withheld from use unintentionally.<br><br>MOD-004-1, B., R8, R9, R10, M11, M12, M13 use of the terms "tag" or "Interchange Transaction Tag" which is inconsistent with NERC INT and NAESB CI BP standards where specific reference to "tag" or "e-Tag" has purposefully been avoided in those standards. The term Request For Interchange (RFI) refers to a collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink BA. Or the term Arranged Interchange refers to the state where the Interchange Authority has received the Interchange information (initial or revised) and has distributed that information for reliability assessment. I believe that in these requirements, Arranged Interchange is the more appropriate language.<br>Response: The drafting team has modified the standard to use the term Arranged Interchange.<br><br>MOD-004-1, B., R10 requires, without exception, that all submitted Arranged Interchange using CBM must be approved. This would force TSPs to potentially approve malformed transactions possibly citing incorrect contract arrangements, incorrect connectivity, etc. Perhaps the requirement could state the TSP shall approve all valid requests to schedule CBM. The drafting team might consider requiring the TSP or other approval entities to supply a meaningful reason for denying a CBM schedule.<br>Response: We believe that in a capacity emergency, an import of the energy is more important that ensuring the details of assignment refs and the like are correct. Note that Balancing Authorities are not prohibited from denying the Arranged Interchange; this is dealing solely with the Transmission Service Provider. |

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| | MOD-008-1, B., R1 transmission service providers are already required by FERC to file and post Attachment C - Methodology To Assess Available Transfer Capability – which includes discussion of the provider's TRM methodology. This requirement to create a separate implementation document creates an undue burden on the industry. In addition, transmission customers will have two different documents to review and TSPs two different documents to maintain.<br>Response: The standard does not preclude a Transmission Service Provide from using one document to meet both requirements.<br><br>MOD-008-1, B., R1.1 suggest modifying to read: "For each path or flowgate that ATC or AFC is calculated, describe how each of the following components of uncertainty are used in calculating TRM for each of the ATC time horizons (if not applicable, indicate as such):" The words "ATC time horizons" could be used to eliminate the need for R1.4.<br>Response: The drafting team intentionally avoided the use of the phrase "time horizons" in order to avoid confusion with NERC Compliance Time Horizons.<br><br>MOD-008-1, B., R.3 what "request" is being referred to? Should it read "…seven calendar days of a request from:"? Or should "of a request" be removed as a typo?<br>Response: The team reviewed this requirement. Based on your comments and others the team made several changes that should address your concerns:<br>#1: R4 on the TSP was removed, it did not make sense for the TSP to serve as aggregator for the Transmission Operators material and would be burdensome on some TSP to have to respond to requests for information that is not theirs.<br>#2: R3 was modified to say make available instead of provide to better reflect the phrasing in other standards and to indicate that shipment of the material is not required, a posting such as a secure FTP site could be sufficient.<br>#3: R3 was modified to require a response to the requestor with the material requested, not a blanket response to all parties listed.<br>#4: R3 was modified to allow for 30 days instead of 7 days. While the material should be readily available, it is more common to allow 30 days for non critical information transmittal and this resolves the concern at some smaller entities over holidays and vacations.<br>#5: Due to the elimination of R4, R3's list of possible requestors was expanded.<br><br>MOD-008-1, B., it seems that R1, 2, and 5 could be merged together into a new R1 TRM calculation and documentation. R3 and 4 could merged together into a new R2 on TRM data sharing.<br>Response: While we agree these items could be merged, we believe it is more appropriate at this time to keep them as separate requirements. |

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| | MOD-029-1 inclusion of the Rated System Path methodology is greatly needed and appreciated. The drafting team was wise in including it and should be thanked for their efforts.<br>Response: Thank you for your supportive comment.<br><br>MOD-029-1 suggest reordering R4 to be R1.<br>Response: The SDT has reordered R3 and 4 to address this comment.<br><br>MOD-029-1 R1 (modeling requirements) should include the statement that the data listed below should reflect the expected conditions for the applicable time period.<br>Response: The drafting team agrees and has modified R1 to address your concerns.<br><br>MOD-029-1 delete R2.7 as it, in its current form, does not provide the entire paradigm contained in the WECC's Procedures For Regional Planning Project Review And Rating Transmission Facilities.<br>Response: The SDT believes this is covered in section 3 of the WECC PCC handbook.<br><br>MOD-029-1 in R6, is the "non-firm capacity reserved for NITS" the same as Secondary Network Service (i.e., NN-6)?<br>Response: It is the same as Secondary Service and the requirement has been revised to reflect that.<br><br>MOD-029-1 in R7 & R8, what are "Postbacks"? This term is not used in the west.<br>Response: This term came from Order 890; to the drafting team's knowledge, it has generally not been used in the East or ERCOT either. The SDT believes that postbacks are used in the West (e.g. release of unscheduled firm as non-firm ATC), but are not referred to in this fashion. The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks.<br><br>MOD-029-1 in R5, R6, R7, & R8, calculation of ETC and ATC are commercial concerns and should be addressed in business practice standards NAESB and enforced through FERC's adoption of those business practice standards into the CFR.<br>Response: The drafting team does not believe these are only commercial concerns. If calculated correctly, ATC should be a reasonable approximation of what flows are expected on the system at a given point in time. Ensuring that this number is accurate will help ensure that entities do not oversell their systems into overloads.<br><br>MOD-029-1 in R8 the requirement says we are to use the same formula for all horizons – this is incorrect. For the real-time, same-day time frame, we release all unscheduled capacity as non-firm ATC. As such, the formula would read:<br>ATCNF = TTC – Scheduled ETCF – Scheduled ETCNF – CBMS – TRMU + Counter-schedulesF + Counter-schedulesNF |

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| | Response: It is the SDT's understanding that NAESB will incorporate unscheduled capacity in postbacks. The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks. Therefore, the requirement is correct as written.<br><br>MOD-030-1 it is unreasonable for TSPs to convert AFC values into ATC values simply because FERC regulations fail to contain the term AFC. For large systems using this methodology, posting thousands of ATC values benefits no one if AFC values can give transmission customers a better picture of available capability of the transmission system. It is recommended that TSPs using MOD-030-1 post AFCs and provide customers tools to either convert AFC information to specific POR-POD ATCs or tools which indicate the feasibility of a transaction from POR to POD.<br>Response: The SDT has modified the standard such that it does not require this conversion, but requires that if the conversion is done, it be done as described.<br>Thank you for the opportunity to comment. |
| Response: Please see in-line responses. | |
| Salmon River Electric Cooperative | 1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.<br><br>Please see responses to the WECC MIC MIS ATC Drafting Team.<br><br>2) In reference to MOD-030-1/R10, the requirement should be altered as follows: "The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC's for its network and provides a tool for AFC-to-ATC conversion (in BPA's case, Power Utilization Factor Calculators). We believe at this time that this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.<br>Response: The standards do not preclude the use of a tool to create ATCs from AFCs; nor do they require the posting of ATCs. |
| Response: Please see in-line responses. | |
| Salt River Project | SRP supports the WECC MIC MIS ATC Drafting Team and WestConnect responses to this questionnaire. The comments offered below represent additional comments that have not been addressed by the WECC or WestConnect comments but are noteworthy nevertheless.<br><br>MOD-001<br>MOD-001-1 R1."Each Transmission Operator shall select one ATC methodology…" should be changed to "Each Transmission Service Provider shall select one ATC methodology…" to allow the entity that calculates ATC (R2) to choose the methodology.<br>Response: The STD believes that the functional model indicates the choice is that of the Transmission Operator. |

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| | MOD-001-1 R2 FERC regulations in 18CFR37.6 require postings for the time periods in R2.1, R2.2 and R2.3 for only constrained paths and only for firm ATC.<br>(1) Please explain the rationale for applying this regulation to unconstrained paths and to non-firm ATC for which FERC has different rules in place.<br>(2) Also, please explain the rationale for calculating more frequently than data is required by FERC to be posted.<br>(3) Consider removing R2 from the standard and instead referring to FERC regulations.<br>Response: The drafting team believes that the calculation of both Firm and Non-Firm ATC supports NERC's reliability goals, and is allowed to be different from the CFR. The drafting team believes that these calculation time periods support NERC's reliability goals, and is allowed to be different from the CFR. Note that MOD-001 R2 does not address posting requirements; these will be addressed by NAESB.<br><br>MOD-001-1 R2. If R2 remains, "Each Transmission Service Provider shall calculate ATC values for the time periods listed below…" should read "Each Transmission Service Provider shall calculate Firm ATC values for each constrained Posted Path for the time periods listed below…"<br>Response: The drafting team disagrees that this should only apply to Firm calculations.<br><br>MOD-001-1 R3.4 and R3.5 The term "transfer capability" is used in these two standards. As R3. describes the ATCID presumably the term used here means "Available Transfer Capability" and should be changed to this term for clarity.<br>Response: The SDT uses the term "transfer capability" because we are referring to any of the three methodologies and their associated transfer capabilities (ATC and TTC).<br><br>MOD-001-1 R4. and R5. While MOD-001-1 R4. directs the Transmission Service Provider to set the value of counterflows to zero for the calculation of firm ATC unless otherwise specified within the Transmission Service Provider's ATCID, no such similar standard exists to direct the Transmission Service Provider to set counterschedules to zero for the calculation of firm ATC under MOD-029-1.<br>This presumed oversight points out the risk involved when having one standard require use of a variable while another standard sets the value of that variable.<br>Another reason MOD-001 R4. and R5. should be moved from MOD-001-1 is that they do not fit into the Standard Drafting Team's explanation of the standard which is the following:<br>"MOD-001 – Available Transfer Capability. An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data."<br>SRP, therefore, recommends that:<br>(1) MOD-001-1 R4. and R5. be moved into each of MOD-028, MOD-029, and MOD-030. (2) SRP also recommends that when R4 and R5 are moved into MOD-029 they be modified to use the same term used in MOD-029 R7 and R8. That is, MOD-029 R7 and R8 currently use the term Counter-Schedules and MOD-001-1 R4 and R5 currently use the term counterflows. These terms should be the same.<br>Response: The drafting team has modified the approach to counterflows in the standards based on the comments |

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| | provided. R4 and R5 were removed because all entities were allowed to modify the default values in their ATCID and we were concerned that the use of the defaults could conflict with planning and operating studies. The Drafting Team modified the requirement for the ATCID in MOD-001 with respect to how the TSP handles counterflows more detailed and clarified that counterflows include counterschedules.<br><br>MOD-001-1 R6. Perhaps instead of requiring e-mails it would be more efficient for the NERC Standards Drafting Team to request that NAESB develop a standard to require the ATCID, TRMID, and CBMID be posted on OASIS. Then R6 could be removed as a standard.<br>Response: The intention of this requirement is to make the entity changing notify entities impacted by the change. While the SDT is not opposed to this information being posted on OASIS, this would not eliminate the need for R6. However, the specific reference to e-mail has been removed from the requirement, and instead included as an example in the measures.<br><br>MOD-001-1 R9. (1) Please explain how "update ATC" is different from "Post ATC" and (2) If it is the same thing, please remove the standard and work with NAESB to develop such a standard.<br>Response: By "update ATC," the drafting team meant that the value which the provider has calculated must be either recalculated or confirmed to not need recalculation. We have modified the language to require recalculation. This number is the number that is used internally by the TSP and shared with neighbors pursuant to MOD-001 R10. NAESB is drafting a standard related to the posting of this number for market consumption.<br>MOD-001-1 R9. (1) Please explain the rationale for requiring the Transmission Service Provider to "update" ATC at minimum frequencies as this standard does not support the goals of consistency or transparency. Each unnecessary calculation is a chance for the calculation, no matter how automated it is, to miscalculate and lead to lack of consistency. (2) If R.9 is not removed, it should be reworded from "…shall update ATC at a minimum on the following frequency" to "shall review and update if necessary ATC at a minimum on the following frequency". The way this would be measured is there would be a violation if a variable changed and the ATC calculation was not updated within a certain time frame.<br>Response: The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br><br>MOD-001-1 R10. As currently worded the data items listed must be provided by any of the entities listed and anyone can ask for the data. R10 should be reworded from "Within 14 calendar days of a request of any Transmission Service Provider, Planning Coordinator…" to "Within fourteen calendar days of a request by any Transmission Service Provider, Planning Coordinator…"<br>Response: This change has been incorporated in the rewrite of the requirement.<br>Violation Severity Level for R9. (1) The level of complexity suggested in this violation severity level will be very difficult to track and police. It is impractical and should be greatly simplified to make it manageable. (2) The use of the phrase "not calculated" also makes the description difficult to understand if not incorrect. For example, the description in the Lower VSL column reads "For Hourly, not calculated within 5hrs … etc" Reading that literally if I |

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| | calculate Hourly 5 or more hours after the hour in question I have satisfied the criteria for the Lower VSL. This was obviously not the intent. A more appropriate wording for this description would be "For Hourly, calculated from 1 to 5 hours after the fact … etc" It is recommended that the description for all the levels of compliance for this requirement be changed replacing the phrase "not calculated" with "calculated" and changing the rest of the descriptions appropriately.<br>Response: The SDT has modified the VSLs to incorporate the suggested concept.<br><br>MOD-029<br>MOD-029-1 R1.12 The wording of this requirement does not match the form of those that precede it (i.e. R1.1 thru R1.11). It is a sub-requirement of the overall requirement R1. which stipulates that the TOP use a model to calculate TTC that "meets the following criteria:" The other sub-requirements stipulate that the model "includes" or "uses" or "models" certain items. R1.12 as written stipulates that the model "identifies" the percent fault damping used. This requirement would be more appropriately located in the requirement which stipulates what the study report must identify (R2.8) rather than what the model must identify.<br>Response: The SDT has modified the requirement to incorporate the suggestion.<br><br>MOD-029-1 Violation Severity Level for R1. This is a two part requirement for each of the four levels of severity. The first part is reasonable but the second part is not practical. To verify that the facility ratings used by the TOP in the model he used to calculate TTC are the same as those specified by the TO, the compliance person would have to manually compare the rating supplied with the rating used for hundreds even thousands of facilities in the model. Moreover, this would have to be done for every model used for every TTC established for every Posted Path. There may be many models representing several different years in the future. Even if you could overcome that hurdle and you found a few facility ratings that were wrong in a model, how would you verify that "…one of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths?" An erroneous facility rating is only important if it should have been the limiting factor but wasn't. You could only determine that if you corrected the erroneous facility rating in the model and rerun the study. Thus this test for compliance is very impractical and should be modified.<br>In the WECC, facility rating coordination is done by sharing the model with the effected entities before running the study. Once the affected entities have reviewed the model and are satisfied that it models their system appropriately they give their ok to run the study. (1) The requirement should be changed to say that the TSP shared the model with affected entities for their review of facility ratings. (2) The measure would be that the TSP can demonstrate that each of the affected entities reviewed the model and are satisfied with it. (3) The vsl would be that the TSP was able to demonstrate that all but one or two etc of the affected entities reviewed the model and were satisfied with it.<br>Response: The SDT agrees and has added a new R1.2. , M1.4 and modified the VSL for R1. to reflect the changes suggested in your comments.<br>MOD-029-1 R7 Please explain the reliability reason for requiring Counter-SchedulesF in the formula for ATCF.<br>Paragraph 212 of Order 890 reads in part, "(1) for firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows." |

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| | Response: Since FERC did not require the use of counter-schedules in the firm calculation, we will not do so either. However, we have included the term such that a TSP can include counter-schedules if they desire. Note that the value is determined at the TSPs discretion. In addition the standards have been modified to allow for the use of zero for any of the elements of the algorithms.<br><br>MOD-004<br>MOD-004-1 Violation Severity Level for R3 The Moderate and High VSL columns each have two subparts. The wording for the first subpart for each is identical. Thus if I don't comply with the first subpart it is unclear whether the level of non-compliance is Moderate or High.<br>Response: This has been corrected so that lacking 1 item is Medium, lacking 2 or more is High.<br><br>Also, the second subpart for the Moderate and High VSL columns are very similar in wording and are overlapping. If the GCID changed by more than 20MW but not more than 30MW the noncompliance falls into both the Moderate and the High VSL.<br>Response: This has been corrected to eliminate the overlap.<br><br>MOD-004-1 Violation Severity Level for R7 The phrase "did not provide" should be changed to "provided" in all four levels of severity because the way it is currently written an entity could provide the requested data within the required seven days and still be non-compliant.<br>Response: The SDT has modified the VSLs to incorporate the suggested concept.<br><br>MOD-008<br>MOD-008-1 Throughout MOD-008-01 including in the "Applicability" section the term "Transmission Operator" should be replaced with the term "Transmission Owner". In cases where a line is jointly owned, the Transmission Operator will calculate TTC of the facility, but each individual Transmission Owner will calculate their own TRM. It is not correct to say the Transmission Operator of the line tells the other line owners what their TRM will be.<br>Response: The way entities are currently organized and the functional model do not always align due to the variety of organizational structures and the developmental state of the Functional Model and revising the functional model is beyond the scope of this team. There has been much discussion by the team on what part of the functional model is assigned to what requirements, and while the team would not claim to have found the perfect fit, we do believe we have found the best fit for the current model.<br>Based on the model as currently written the team believes the Transmission Operator is the correct party. There is nothing in this requirement or the functional model that precludes the Transmission Operator from contracting with the Transmission Owners to provide the method, calculation, values and representation on this issue.<br><br>MOD-008-1 Future Development Plan: Anticipated Actions #7 (first page of the standard) The phrase "Board Adopts MOD-001-1" should be changed to read "Board adoption" to be consistent with the other standards. |

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| | Response: The SDT has corrected this typographical error.<br>MOD-008-1 Violation Severity Level for R3 "Moderate Level" should be reworded as follows: The Transmission Operator provided its TRMID to all but one entity specified in R3. OR provided its TRMID to all entities in 14 calendar days or more but less than 30 calendar days.<br>MOD-008-1 Violation Severity Level for R3 "High VSL" should be reworded as follows:<br>The Transmission Operator provided it's TRMID to all but two entities specified in R3. OR provided its TRMID to all entities in 30 calendar days or more but less than 60 calendar days.<br>MOD-008-1 Violation Severity Level for R3 "Severe VSL" should be reworded as follows:<br>The Transmission Operator did not provide the TRMID to any of the entities specified in R3 OR provided its TRMID to all entities in 30 calendar days or more but less than 60 calendar days.<br>Response: All R3 VSL's were adjusted based on comments that drove a change in the requirement. The team believes this has addressed your concern, although not exactly in the manner suggested.. .<br><br>AFFIRMATIVE COMMENTS:<br>In addition to the affirmative comments provided in the WECC and the WestConnect comments SRP wishes to emphasize that it is very supportive of the drafting team's incorporation of the following attributes into the draft standards:<br>Twelve Month Implementation Plan – The draft standards impose new requirements for the calculation of ATC and it's components that will require substantial effort and time in order to implement. It is envisioned that at a minimum twelve months will be required to make the changes necessary to conform to the new standards.<br><br>MOD029 Modeled after WECC Path Rating Methodology – SRP congratulates the drafting team for giving full consideration of the WECC Path Rating Methodology when drafting the MOD029 Rated System Path Methodology Standard. The WECC methodology has been developed and refined over a number of years and has served the west well. We are happy that the key features have been retained in MOD029. The requirements in R2. and its sub-requirements are particularly important to us and we would be very disappointed if any of the features of these requirements are degraded as a result of the drafting teams response to industry comments.<br>Response: Thank you for your supportive comments. |
| Response: Please see in-line responses. | |
| Santee Cooper | MOD001 R3.3<br>Make sure that the data retention requirements are not more stringent than the FERC Requirements. Also, be consistent with the data retention requirements instead of having some that say most recent calendar year plus current year and some say three calendar years.<br>Response: NERC has its own data retention requirements, which are reflected in the standards.<br>MOD004 Effective date should list the six standards consistent with all the other standard's effective date.<br>Response: The SDT has modified the language to be consistent with the other standards, recognizing that the |

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| | standards will now be posted for separate ballots.<br>MOD004 R6 need to be consistent with wording.  It should either read "Within five business days" or "Within five calendar days".<br>Response: The SDT has modified the standard to consistently refer to “calendar” days.<br>MOD004 consider removing R8, R9, and R10 since these are related to Business Practices.<br>Response: The SDT agrees these are related to business practices; however, also believe that the specific requirements are reliability oriented.<br>In MOD029 consider adding some detail requirements related to the ATCID similar to details outlined in MOD028.<br>Response: Much of this detail is intended to be included in the study reports, rather than the ATCID.<br>Real-time Planning, Operations Planning, and Long-term Planning should be defined in the NERC Glossary.<br>Response: We have definitions for these terms as they relate to the Compliance Time Horizons.  However, in general, the SDT does not believe it is within their scope of work to define these terms as they pertain to the industry at large. |
| Response:  Please see in-line responses. | |
| SERC ATCWG | MOD-001 Available Transfer Capability<br>R3.1 - Is this requirement consistent with use of the terms "counter flow" and "counter reservation" in the rest of the Standard?<br>Response: The drafting team believes that it is.<br><br>R3.6 - What is the definition of "Allocation" of flow gate capabilities or paths<br>Response: The Drafting Team added detail to this requirement to clarify what the intent is.<br><br>R9:  Is this consistent with communications protocols and NAESB Business Practices?  In addition, it shouldn't be necessary to update a value that hasn't changed.<br>Response: These requirements apply to the minimum calculation times; communication protocols and NAESB Business Practices deal with posting requirements for the calculated values. The Drafting Team has modified the standard so that recalculation is not required unless the calculated values identified in the ATC equation have changed. The other associated standards (MOD-004, 008, 028, 029 and 030) contain requirements for time based updates of the variables in the ATC equation.<br><br>R10:  Insert "its own data" in the first sentence, 3rd line as follows: …Provider shall begin to make "its own data" available on the schedule specified…<br>Response: The addition has been made as requested.<br>Fourteen (14) days appears to be unreasonably burdensome to supply the significant amount of data contemplated - thirty (30) days would be a more reasonable time period we would support.<br>Response: This change has been incorporated. |

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| | In addition, an entity should not be required to supply another entity's data that is used in their models.<br>Response: The SDT has modified the standards to incorporate this requirement.<br>R10.8 - This requirement needs clarification. Why isn't it covered by the rules of counterflow? If not, it should be explained why it isn't or removed from the standard. It seems to fall in and be a part of the TRM standard.<br>Response: This data item is not covered by the rules of counterflow. It is related to how a TSP distributes the impact of a reservation on parallel paths. For entities that use this information, this ensures the data can be requested and exchanged. If this data is not utilized by a TSP then the bulleted item would not apply.<br><br>R10.13 - In an AFC environment, there should not be a requirement to post CBM and TRM on a Posted Path.<br>Response: The requirement has been changed to allow provision of CBM and TRM on a path or flowgate basis.<br><br>R10-13 and R10.14 - It appears that R10.13 and R10.14 should be combined under one Requirement as sections "a" and "b". R10.13 applies to Rated system Path and R10.14 applies to AFC. There should also be a measure that applies to the top level.<br>Response: The bullets have been reworded to clarify which data applies to which calculation method.<br>MOD-004 Capacity Benefit Margin<br>R2: The acronym "CBID" in the 2nd line of the first sentence should be "CBMID".<br>Response: The SDT has corrected this typographical error.<br><br>Entities should have a more reasonable time frame of fourteen (14) calendar days to make CBMID and any changes available to applicable parties Requirement 4:<br>Response:<br>R4.1.2.2 - Entities should have the option to use a lower threshold than 3%, if desired.<br>Response: The SDT has added a clarifying footnote that entities are allowed to use thresholds lower that those specified if desired.<br>R6 - Fourteen (14) calendar days for providing requested CBM information would be more reasonable.<br>Response: the drafting team believes that five days is adequate.<br><br>R7.1 and R7.2 - Fourteen calendar days for providing CBM supporting data would be more reasonable.<br>Response: The drafting team has modified the standard to allow 30 days.<br><br>R9: Add "within the bounds of reliable operation" to the end of the R9 requirement description.<br>Response: The SDT has incorporated the suggested language into the requirement. |

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| | MOD-008 TRM Calculation Methodology<br>R3, R4, R5 - Fourteen calendar days for providing TRM calculations and supporting data would be more reasonable.<br>(Response for R3, R4) The team reviewed this requirement. Based on your comments and others the team made several changes that should address your concerns:<br>#1: R4 on the TSP was removed, it did not make sense for the TSP to serve as aggregator for the Transmission Operators material and would be burdensome on some TSP to have to respond to requests for information that is not theirs.<br>#2: R3 was modified to say make available instead of provide to better reflect the phrasing in other standards and to indicate that shipment of the material is not required, a posting such as a secure FTP site could be sufficient.<br>#3: R3 was modified to require a response to the requestor with the material requested, not a blanket response to all parties listed.<br>#4: R3 was modified to allow for 30 days instead of 7 days. While the material should be readily available, it is more common to allow 30 days for non critical information transmittal and this resolves the concern at some smaller entities over holidays and vacations.<br>#5: Due to the elimination of R4, R3's list of possible requestors was expanded.<br><br>(Response for R5) Providing the TRM calculation to the TSP is considered by the team to be an important step. In the teams opinion this value should be sent to the TSP's and transmission planners as soon as it is prepared and adopted by the transmission operator. However "as soon as" is not an auditable requirement. The team did not want to require transmission of the value prior to adoption, so settled on a 7 day time frame as reasonable and practical from an evidence standpoint.<br><br>MOD-028 Area Interchange Methodology<br>The existing wording for R3 (and R4) is very difficult to follow. Also, it appears that the drafting team intends that a peak and an off-peak TTC value will be calculated each day. Please consider using wording such as the following to add clarity:<br>R3 - When calculating TTC values (for intra-day and next day) for Posted Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's Area. The Transmission Operator shall also include comparable data associated with external Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers, and by any other Transmission Service Providers with which coordination agreements have been executed. The Transmission Operator shall include (at a minimum):<br>R3.1. Expected generation and Transmission outages, additions, and retirements.<br>R3.2. Load forecasts for the on-peak periods and the off-peak periods being calculated. At a minimum, a peak value and an off-peak value shall be calculated for each day.<br>R3.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run. |

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| | R4 - Wording similar to R3 can be used in R4 (as shown below). Alternately, R4 could simply be combined into R3 by changing "(for intra-day and next day)" in the first sentence to "(for intra-day through Month 13.)"<br>R4. When calculating TTC values (for time periods beyond next day) for Posted Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's Area. The Transmission Operator shall also include comparable data associated with external Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers, and by any other Transmission Service Providers with which coordination agreements have been executed. The Transmission Operator shall include (at a minimum):<br>R4.1. Expected generation and Transmission outages, additions, and retirements.<br>R4.2. Peak Load forecasts for the periods being calculated.<br>R4.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.<br>Response: The drafting team incorporated your suggestions based on the language above for R3 and R4.<br><br>R5.3 - What is the definition of an interface point? This would require artificially modeling a generator as a source or sink. It is suggested that the words "the interface point with" should be deleted from the language in bullet points 3,4,7 and 8 under R5.3.<br>Response: We have eliminated the use of the phrase interface point.<br><br>R11 and R12 - What is a "postback" as defined by NAESB?<br>Response: The SDT has clarified the term post back by incorporating the following definition: "Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service." Note that NAESB will be defining specifically what values should be considered when determining Postbacks.<br><br>MOD-030 Flowgate Methodology<br>R2.1.1 - The current definition makes every facility a flowgate. Suggest changing the wording as follows, "Any facility within the Transmission Operator's area based on thermal, stability or voltage limits is eligible to become a flowgate." The requirements that follow (R2.1.2 and R2.1.3) would be sub-requirements of R2.1.1 that would be used to determine the subset of all transmission facilities described in R2.1.1 that become flowgates.<br>Response: The Standards Drafting Team (SDT) has modified the language of this requirement to limit the scope.<br><br>R2.1.2.1 - This requirement is only applicable if the planning studies and operating studies use the same methodologies. If the planning studies use a TTC methodology then all transmission facilities may be contingencies. In AFC studies only the select flowgate definitions that contain contingency elements would be included. Recommend removing this requirement.<br>Response: The SDT has modified this to require consistent consistency assumptions, rather than contingencies. The |

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| | language also now includes the phrase "for the applicable time periods".<br><br>R2.2 - Should be yearly instead of quarterly. Delete the word "definitions" from the sentence.<br>Response: The SDT changed the requirement to annually for internal flowgates and monthly for external flowgates. The word "definitions" has been deleted from the sentence.<br><br>R3.1 - Recommend that R3.1 be deleted since TFC may be derived from another source such as a subsystem file. This is a common industry practice since it is easier to maintain flowgate attributes in external subsystem files than in the load flow models.<br>Response: R3.1 does not preclude you from using flowgate parameter files.<br><br>R3.4 and R3.5 - Change Reliability Coordinator's area to Transmission Operator's area.<br>Response: The SDT feels that requiring the model to contain the facilities in the RC area will be required for consistent, reliable calculation of AFC. The standard drafting team feels that it will not be burdensome to supply such data even for a small TOP within a large RC. The team has added a statement saying, "Equivalent representation of radial lines and facilities161kV or below is allowed." which should help with the modeling.<br><br>R4.2 - What is the definition of an interface point? This would require artificially modeling a generator as a source or sink. It is suggested that the words "the interface point with" should be deleted from the language in bullet points 3,4,7 and 8 under R4.2.<br>Response: The SDT has eliminated the use of the phrase interface point.<br><br>R5.1 - Recommend rewording of R5.1 to address outage rules. Outage rules are used in to define the set of outages to include in monthly or daily calculations where multiple outage periods exist. An example would be that in monthly AFC calculations all outages for the month are not included. Only the set of outages that meet the outage rules (i.e. all EHV with a duration of greater than 7 days or all outages that occur on the 3rd Wed of the month, etc) The requirement should be reworded to say "all outages that meet the outage rules as specified in the ATCID".<br>Response: R5 has been revised to provide additional flexibility, and entities are required to describe the rules for handling outages during the ATC process in their ATCID.<br><br>R5.2 - Replace the existing wording with the following: "For external third party flowgates and PDF greater than 5%, Use the AFC for each specific flowgate provided by that third party as the AFC for that flowgate."<br>Response: The flowgates to be considered are those that meet the criteria in R2.1; it is not necessary to specify a |

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| | threshold criterion in this requirement.<br><br>R6.3 and R6.4 - The threshold values for calculating impacts should be consistent with the threshold values contained in MOD-028.<br>Response: The drafting team has discussed the distribution factors extensively and set them to appropriate levels.<br><br>R7.2 and R7.4 - The threshold values for calculating impacts should be consistent with the threshold values contained in MOD-028.<br>Response: The drafting team has discussed the distribution factors extensively and set them to appropriate levels.<br><br>R8 - What is a "postback" as defined by NAESB?<br>Response: The SDT has clarified the term post back by incorporating the following definition: “Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.” Note that NAESB will be defining specifically what values should be considered when determining Postbacks. |
| Response: Please see in-line responses. | |
| Sierra Pacific Resources Transmission | In MOD-001, not one Requirement should have a VRF other than Lower. Certainly for the Rated System Path Methodology, not calculating ATC means not posting ATC, means not selling Transmission, means not allowing any flow. No flow is less reliable (i.e., greater risk?) than some flow? No. While it is certainly important to have transparency in the ATC methodology, including ATC/TTC calculations, a VRF of Medium is excessive. Having an incorrect ATC value 13 months in the future is in no way materially affecting reliability.<br>Response: The SDT does not agree. Not posting ATC may result in no reliability concern, but this standard does not address posting of ATC. Rather it addresses calculating of ATC. Not calculating ATC means not knowing what has been sold, which means not knowing what may be scheduled, which means not knowing what may be flowing, which means not knowing whether you should expect an SOL or IROL in the future, which means not knowing whether or not additional sales would cause an SOL or IROL. While these standards are not about the actual selling of transmission, they are about ensuring the data used to make the decision of whether or not to sell is accurate, is consistently derived, and includes consideration of activities beyond the Transmission provider’s border. As such, the STD believes that in several cases, a VRF of medium is justified.<br>GENERAL<br>1) The SPR companies support retention of the three methods recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028).<br>2) The SPR companies strongly support the retention of the proposed one-year implementation period.<br>3) The SPR companies support allowing NAESB to address all “posting” issues as they directly affect OASIS and any reference to postings should be removed.<br>MOD-001 Umbrella<br>1) The SPR companies support allowing the use of more than one methodology for calculation of ATC by any one entity. For example, the SPR companies support allowing any entity to use the Flowgate methodology inside their |

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| | affected area while also using the Rated System Path methodology at its boundaries.<br><br>2) The SPR companies support allowing each entity to specify in its ATCID how it will treat counterflows / schedules. (R4., R5.) within the methodology each entity chooses. This will allow the entity to use counter schedules instead of counterflows where applicable.<br><br>3) The SPR companies support the aggregation of transmission capacity for grandfathered contracts when shared with neighboring requestors.<br><br>4) The SPR companies support the specifically limited universe of entities to which data sharing is required as prescribed in R10.<br><br>5) The SPR companies support those comments submitted by SERC specifying suggested changes to the VRFs. However, this Team makes no comment on the VRFs as they affect MOD-28.<br><br>MOD-029 RATED SYSTEM PATH TTC, ETC & ATC<br>1) The SPR companies support retention of the requirement(s) in R2.2 that accommodate paths which are “flow limited” by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing practices without re-inventing the wheel where no such effort is required to meet FERC’s goals of transparency and consistency.<br><br>2) The SPR companies support retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.<br><br>3) The SPR companies support retention of the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.<br><br>4) The SPR companies support retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts, associated litigation and potential renegotiation of associated operational agreements while supporting FERC’s mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation methodologies is required.<br><br>5) The SPR companies support the adoption of a definition for counterflow to clarify its application in each equation."<br><br>MOD-004 CBM<br>1) The SPR companies support the concept of allowing the LSE to decide how much CBM it needs to satisfy its resource adequacy requirements and the TSP determining how the total CBM requirement for all requesting LSE’s is |

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| | allocated among paths. This is the proper division of labor.<br><br>2) The SPR companies support allowing the LSE scheduling rights to the CBM after declaration of an EEA2 or higher condition.<br>Response: Thank you for your supportive comments. |
| Response: Please see in-line responses. | |
| Snohomish PUD | 1) We support the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.<br><br>Please see responses to the WECC MIC MIS ATC Drafting Team.<br><br>2) MOD-030-1<br>R10 states that the TSP shall convert Flowgate AFCs to ATC for Posted Paths. Snohomish, as a major BPA customer, has a concern that if AFCs must be converted to ATCs for any possible constrained POR/POD combination then conducting with our transmission provider will become very difficult. This would not have the effect that the Commission wanted as far as transparency. The explosion of data from ten flow gates to thousands of POR/PODs on the OASIS site will make it difficult to do business. BPA already provides its' customers with an easy to use tools to calculated the impact a request has on a flow gate.<br>Response: The standards do not preclude the use of a tool to create ATCs from AFCs; nor do they require the posting of ATCs. |
| Response: | |
| The Southeast Coalition | Please see below.<br>ATCID, TRMID, and CBMID Documentation:<br>Transmission Service Providers should make their ATCID, TRMID, and CBMID documentation publicly available as soon as these documents are ready but no later than 60 days before implementation. This is a very important issue for market participants who need to be aware of the TSP changes with enough lead time so that they can adjust their business processes accordingly. For those regions which have not had CBM in the past but TSPs decide to set aside transmission capacity for this purpose, according to the Standard, the CBMID should be posted 90 days before implementation to allow for consultation with NERC and a meaningful vetting of issues.<br>Response: NAESB will be addressing the posting of information to market participants.<br>Stakeholders Participation:<br>Stakeholders' participation in the development and continued improvement of ATC standards and associated implementation is a key element to achieve success. NERC itself recognized the benefit and significance of the stakeholder process in the development of reliability standards. Order 693 at Cite 183. Thus, establishing forums and processes for stakeholders' on-going participation at NERC and regional levels is a MUST. These stakeholder processes are required to vet issues and gain support for the initial approval of the ATC standard and on-going changes to it. NERC should clearly set out and document the processes by which comments and suggestion of stakeholders will be gathered, evaluated, and incorporated in the Standard. |

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| | Response: NERC utilizes an ANSI-accredited process to ensure stakeholder participation, and encourages participation in any of its standards development efforts.<br><br>Distribution Factor Cut-Off:<br>MOD-030 (R10). Requirement 10 of MOD-030 establishes the mathematical equation to convert AFC values to ATC values and sets the distribution factor cut-off to 3% for ATC calculations. The following statement is included in requirement 10 of MOD-030: "a flowgate is impacted by a path if the Distribution Factor for that path is greater than 3%". Although most TSPs currently use a 3% distribution factor cut-off, there is no need to "hard-code" a value in the Standard and, by doing so, take away the flexibility of selecting a more appropriate value which could be set on a per flowgate basis. Furthermore, the TLR process uses a 5% distribution factor cut-off for transmission service curtailments which raises a potential conflict with the 3% cut-off value proposed for ATC calculation purposes.<br>NERC should address the difference between distribution factor cut-off values for ATC calculations and the TLR process to ensure that this difference does not create undue discrimination. Additionally, a minimum value of 3% for distribution factor cut-off could be included in the ATC standard provided TSPs are given flexibility to use a higher cut-off value which could be set on a per flowgate basis. Further, consistent with the transparency requirement of Order 890, TSPs should be required to provide justification for the distribution factor cut-off value(s) used in their ATC calculations.<br>Response: All of the cutoffs have been examined by the standard drafting team and have been set to appropriate levels. Some flexibility has been added to the cutoffs. Requiring justification of cutoff levels did not seem appropriate because it would be challenging to evaluate the validity of such a study.<br>ETC Calculation and Base Case Contingency Overloads:<br>MOD-030 (R6). Requirement 6 of MOD-030 attempts to define calculation of ETC based on flowgate impacts of various transmission service and load components. However, the ETC calculation as defined in requirement 6 is loose and unclear. More importantly, this requirement - as currently stated in the Standard – does not ensure that TSPs do not overstate flowgate capacity set aside for ETC purposes. FERC, in Order 890 Cite 243 & 244, has directed NERC to define ETC in a transparent and consistent manner to reduce the potential for undue discrimination. The following is an extract of Order 890 Cite 243: "To achieve greater consistency in ETC calculations and further reduce the potential for undue discrimination, the Commission adopts the NOPR proposal and directs public utilities, working through NERC and NAESB, to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses".<br>In some regions, overstatement of ETC leads to the appearance of "Base Case Contingency Overloads" (BCOs) which effectively means that the ETC impact on certain OTDF flowgates is greater than the flowgates capacity and thus, these flowgates are overloaded in the ATC power flow models. BCOs can be expressed by the following relationship:<br>BCO on a flowgate = ETC impact on the flowgate > Flowgate TFC<br>BCOs can occur in any of the ATC calculation time frames and may be spread over an entire region or be localized. In some TSP areas, BCOs have become a chronic situation and are mainly due to modeling flaws in the calculation of ETC. This causes serious problems for customers trying to get access to the transmission system. One of the main causes of chronic BCOs is the dispatch model which does not take into account transmission limitations and thus, yields unrealistic results.<br>Requirement 6 of MOD-030 does not address the dispatch model in enough detail to prevent unrealistic ETC results |

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| | nor includes sanity checks to validate ETC calculations. Furthermore, TSPs are not required to show that the dispatch model in their ATC calculations is feasible and resembles actual system operation. Thus, it is our opinion that the ATC standard has not fully met the ETC calculation requirement established in Order 890 at Cite 243 & 244.<br>We believe that, in the calculation of ETC, all resources should be dispatched in a feasible and realistic manner such that transmission limitations are respected to the extent possible. The ATC standard should include clear & detailed guidelines for dispatching generating resources so that accurate and realistic models are used in ATC calculations which in turn should yield realistic ETC values.<br>Response: In MOD-030, the SDT has required the use of dispatch modeling information to determine these impacts, and based on other industry comments, have clarified that the processes used should be contained in the ATCID (pursuant to R3.1). The SDT believes this should help address some of the concerns you describe. With regard to BCOs, we believe this concern should be pursued through NERC Compliance, as this would seem to be either a violation of TPL-001 or it will become a violation of MOD-001 R8.<br><br>As required in Order 890 Cite 290 & 291, TSPs must be required to benchmark ETC calculations against real-time flows to ensure that these values are not being overstated. This will go a long way in reducing the potential for undue discrimination. Furthermore, TSPs should be required to identify and report, on a periodic basis, all BCOs over 5% and chronic BCOs to NERC for further investigation and action.<br>Response: This will be addressed in NERC's future work on these and other standards.<br><br>Monthly ATC Values:<br>MOD-001 (R2.3). Requirement 2.3 of MOD-001 states that TSPs shall calculate monthly ATC values at least for the current month plus the next 12 months. This requirement should clarify that TSPs currently calculating and posting monthly ATC values for a longer time period should continue doing so. For example, some TSPs have been posting monthly ATC values for 18 months which is useful in providing information to the market and enabling new business. The requirement should be drafted to encourage such TSPs to continue their existing posting practices rather than falling back to the minimum requirement.<br>Response: Entities are free to post more data than is required by the standard.<br><br>Outages and Monthly ATC Values:<br>The Standard does not address in enough detail the modeling of transmission and generation outages in the monthly models used for monthly ATC/AFC calculation. Currently, there are no consistent practices in the industry for including or excluding outages of short duration, i.e. a few hours or days, in the monthly ATC calculations. Consistent with the Order 890 goals of accuracy and transparency, NERC should set clear guidelines on the duration and type of outages to be included in the calculation of monthly ATCs so that this process is transparent and consistent across the various regions.<br>Response: The Drafting Team has incorporated requirements in MOD-001 for the TSP to describe in their ATCID how/when outage criteria such as duration impacts ATC calculations.<br>Dispatch Model and Must Run Units:<br>The Standard has little detail and, practically, no guidelines on the dispatch model used in ATC/AFC calculations, |

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| | except for the following statement included throughout the Standard: "Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run as they are expected to run". This is a high level statement that needs to be developed into clear and measurable requirements to ensure consistency and fairness in ATC calculations. The dispatch model is the most important single factor in the determination of ATC values and, in particular, the modeling of Must Run Units, which is a critical issue. Consistent with the transparency requirement of Order 890, the generation dispatch model used in ATC calculations must be transparent and this issue must be addressed by the Standard.<br><br>To reduce both the potential for undue discrimination and the number of "phantom congestion" incidents, and to improve accuracy of ATC calculations, NERC must develop detailed requirements for the dispatch model used in ATC calculations and establish measurements to evaluate compliance with the requirements. These requirements should be focused on the development and use of dispatch models that are realistic and consistent with well-established operational practices. To ensure that the model resembles actual system operation, the dispatch model should be benchmarked against real-time dispatch and consistency checks should be performed across the various ATC time frames<br><br>Response: The SDT believes this to be outside the scope of the ATC standards. The SDT encourages you to submit a SAR, requesting a new standard be written to deal with modeling of dispatch. |
| Response: Please see in-line responses. | |
| Southern Company Transmission | MOD-001 Comments:<br><br>R10. The language "any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator, each Transmission Service Provider shall begin to make available on the schedule specified by the requester (but no more frequently than once per hour" is too broad. "Any" provider, operator, etc. does not have reliability need for this information on an hourly basis. Much of the information does not change on an hourly basis. Please consider rewording as follows.<br><br>Proposed wording: any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator having a reliability need, each Transmission Service Provider shall begin to make available on a schedule mutually agreed to by the requester and the provider.<br><br>Response: NERC cannot easily create any measures or compliance around the concept of "mutual agreement;" it becomes difficult to assign responsibility. Similarly, determination of "reliability need" is problematic. It is the belief of the drafting team that the language has been crafted in such a way that such compliance would not be difficult (i.e., since the requirement is to make available instead of provide, all this information could simply be posted on a secure website and downloaded by the requester once an hour).<br><br>MOD-028 Comments:<br><br>R3. The existing wording for R3 (and R4) is very difficult to follow. Also, it appears that the drafting team intends that a peak and an off-peak TTC value will be calculated each day. Please consider using wording such as the following to add clarity.<br><br>Proposed wording: R3. When calculating TTC values (for intra-day and next day) for Posted Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's Area. The Transmission Operator shall also include comparable data associated with external Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers, and by any other Transmission Service |

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| | Providers with which coordination agreements have been executed. The Transmission Operator shall include (at a minimum):<br>R3.1. Expected generation and Transmission outages, additions, and retirements.<br>R3.2. Load forecasts for the on-peak periods and the off-peak periods being calculated. At a minimum, a peak value and an off-peak value shall be calculated for each day.<br>R3.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.<br>R4. Wording similar to R3 can be used in R4 (as shown below). Alternately, R4 could simply be combined into R3 by changing "(for intra-day and next day)" in the first sentence to "(for intra-day through Month 13.)"<br>Proposed wording: R4. When calculating TTC values (for time periods beyond next day) for Posted Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's Area. The Transmission Operator shall also include comparable data associated with external Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers, and by any other Transmission Service Providers with which coordination agreements have been executed. The Transmission Operator shall include (at a minimum):<br>R4.1. Expected generation and Transmission outages, additions, and retirements.<br>R4.2. Peak Load forecasts for the periods being calculated.<br>R4.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.<br>Response: The drafting team incorporated your suggestions based on the language above for R3 and R4.<br><br>R5.3. R5 appears to apply to all TTC calculations, however R5.3 appears to be specific to monthly analysis; "the expected schedules using monthly or longer firm Transmission service". Please consider using the same wording as used in MOD-30 R4.<br>Proposed wording: When calculating TTCs for Posted Paths, the Transmission Service Provider shall Use assumptions consistent with the assumptions used in operations studies and planning studies for the applicable time periods, including: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]<br>R5.1. Use all Contingencies meeting the criteria described in its ATCID.<br>R5.2. Respect any contractual allocations of TTC.<br>R5.3. Modeling the impact of point-to-point reservations as follows:<br>Response: The restriction to consider only monthly or longer reservations has been removed.<br><br>Also, the term "interface point" is used several times both in MOD-28 and MOD-30. Please consider a more appropriate term such as balancing area.<br>Response: The SDT has modified the standard to be more explicit. Additional flexibility has also been provided with |

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| | regard to source/sink modeling.<br>R6.1. For Daily TTCs, it has been common practice to use the Monthly TTC value up until a few days prior to when the Daily service commences. This is done because weather and outage information is not substantially more accurate 7 days out than it is 30 days out. Day specific calculations are then performed several times during the current week as weather and outage information becomes more clear. Please consider the following wording.<br>Proposed wording: R6.1. At least once in the calendar week prior to the specified period for TTCs used in hourly, and daily ATC calculations.<br>Response: The standard has been modified with your suggested wording.<br><br>R7. The wording in R7 appears to describe transfers involving single balancing area. Also, the wording does not mention contingency analysis. Please consider the following wording.<br>Proposed wording: Determine the first contingency incremental Transfer Capability for each Posted Path by increasing generation and/or decreasing load within the source Balancing Authority area(s) and decreasing generation and/or increasing load within the sink Balancing Authority area(s) until either:<br>Response: The drafting team believes reaching (respecting) SOL's incorporates contingencies into the process.<br>The wording in b) is confusing. This also might fit better as another bullet under a). Please consider rewording b) and adding it as a bullet under a).<br>Response: R7 has been rewritten to clarify the intent of the drafting team.<br>The language in c) "sum the incremental Transfer Capability and all impacts of Firm Transmission Service that were included in the study model" requires some clarification. It would be helpful to clarify that it may not be appropriate to represent TTC as a simple sum of FCITC and net base transfers. If base transfers are in the same direction as the TTC being calculated, (i.e. base imports modeled when calculating import TTC), a simple summation is appropriate (TTCimport= FCITC + base imports). However, if base transfers are in the opposite direction to the TTC being calculated (i.e. base exports when calculating import TTC), a simple summation is not appropriate (TTCimport= FCITC - base exports is not accurate). The reason is that the counterflow effect of the base transfer usually does not correspond to a 1:1 increase in FCITC, and hence, summing a "negative" base transfer may significantly understate or overstate the TTC. The drafting team appears to have decided to address counterflow impacts in the calculation of ATC in R11 and R12. This approach will work if coordinated with the treatment of base flows in R7c&d. Please consider adding language such as the following.<br>Proposed wording: "Base transfers in the same direction as a TTC path shall be summed with the Incremental Transfer Capability to determine TTC. Base transfers in the opposite direction of a TTC path (i.e. net base exports when calculating import TTC and net base imports when calculating export TTC), which create counterflow effects that cannot generally be reconciled by a simple summation, shall be addressed in the calculation of TTC/ATC as described in the Transmission Operator's ATCID document."<br>Response: The Drafting Team has clarified the language as follows:<br>"-The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as described in the Transmission Service Provider's ATCID, that were included in the study model, or."<br><br>R9. Need to add Conditional Firm Service to the ETCF equation. |

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| | Response: The Drafting Team believes that conditional firm would be included with Firm service.<br>GFF needs to have the phase "reserved on posted Paths" added similar to NITSF.<br>Response: The Drafting Team modify the language as follows:<br>"GFF is the firm capacity set aside for Grandfathered Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities."<br><br>R10. GFNF needs to have the phrase "reserved on posted Paths" added similar to NITSNF.<br>Response: The Drafting Team modify the language as follows:<br>"GFNF is the non-firm capacity set aside for Grandfathered Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities."<br><br>R11. To the extent base transfers provide counterflow impacts, these are already embedded in the TTC values. Is the "CounterflowsF" component of the equation intended to adjust the impact of counterflows resulting from the base transfers, or is it intended to account for counterflow impacts related to new transmission service commitments made prior to new models and transfer capabilities being developed? Please add clarification.<br>Response: It is not the intent of the Drafting Team to include those counterflows already considered within the TTC calculation, but those not included in the TTC consistent with the transmission provider's ATCID.<br><br>R12. Same comments as R11.<br>Response: It is not the intent of the Drafting Team to include those counterflows already considered within the TTC calculation, but those not included in the TTC consistent with the transmission provider's ATCID.<br><br>Also, please consider using the term TRMNf instead of TRMu.<br>Response: We have added an parenthetical to indicated that the "U" stands for "Unreleased"<br><br>CBM should not be in the ATCNf equation as this will result in double counting. CBM is a reservation of TTC which prevents it from being sold on a firm basis. This capacity is sold on a non-firm basis. When an LSE needs to utilize the capacity it reserved as CBM to address a capacity shortfall, the LSE submits a transmission service request providing the specific source and sink information and referencing the need to access CBM capacity. To the extent the CBM capacity had been sold non-firm, those non-firm schedules would be curtailed to enable the LSE's to schedule its firm usage of CBM. This TSR or the subsequent schedule would be reflected in the ETCf value. double count example) ATCnf = TTC - ETCf (includes 100 sched) -CBMs (100). Please consider this definition change.<br>Proposed wording: ETCf is the sum of existing firm Transmission commitments for the Posted Path during that period, which will include any transactions scheduled utilizing CBM capacity, |

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| | Response: We have clarified the definition of CBMs to state:<br>“CBMs is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period”<br><br>Please consider this definition for postbacks.<br>Proposed wording: PostbacksNF are increases to ATC values resulting from transmission service being redirected by customers to other paths or from transmission service not being scheduled by customers during that period, as defined in Business Practices<br>Response: The SDT has clarified the term post back by incorporating the following definition: “Postbacks are positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.” Note that NAESB will be defining specifically what values should be considered when determining Postbacks.MOD-30 Comments<br>R2.1.1. This does not appear to be a criteria.<br>Response: The Standard Drafting Team (SDT) agrees. This requirement has been changed to reflect a more reasonable scope.<br>R2.1.2. This language is confusing regarding first three limiting elements. Also, planning and operating contingencies may include all elements, circumventing the concept of using representative flowgates. Please add clarification of what is intended.<br>Response: The language has been modified to be clearer.<br>R2.1.3 Any limiting element interconnection wide-seems overly broad. Should this be limited to those in which the TSPs area had some minimum impact?<br>The SDT agrees. We added the phrase, “within the last 12 months” to this requirement to limit the scope.<br>R2.3. Since SOL is associated with contingency loading, the TFC is associated with the thermal ratings of the facility, not necessarily the SOL of the flowgate. Please see suggested TFC definition.<br>Response: Flowgates usually have contingencies also, the associated TFC would be the SOL value.<br>R3 This section describes modeling requirements. It does not include provisions for outages, load forecasts, etc. R5 discusses outages when calculating AFCs. Is this intended to be done by inclusion in the modeling? If so, should this be moved into R3? Similarly, R6 discusses peak load forecasts when determining the impact to ETC. Is this intended to be included in the modeling. If so, should this be moved into R3?<br>Response: R3 discusses where the TSP obtains the model from and how often. R5 discusses using the models and other data to calculate AFCs.<br>R9. See comments related to CBM in R12 of Mod 28.<br>Response: See response related to CBM in R12 of Mod 28.<br>R10. This language is confusing. Also, although "P" is defined, it is not used in the equation. Please consider adding some simple language such as the following.<br>Proposed wording: "TTC is determined by dividing the most limiting flowgate capacity associated with a posted path by the path's distribution factor for that flowgate."<br>Response: The equation has been updated to use the defined “P”. With this correction, the SDT believes the |

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| | language as written is clear. |
| Response: Please see in-line responses. | |
| SPP | MOD-001-1<br>R1<br>1.Is it correct that R1 assumes that all the Transmission Operators within the Tariff footprint of a Transmission Providers shall agree upon the applicable ATC Methodology for the Tariff footprint and the TSP shall base the ATC Calculations and the ATCID document on the selected ATC methodology or methodologies. Meaning R1 and R2 are related.<br>Response: It is correct that 1 and 2 are related, but it is not correct to assume that the Transmission Operators "will agree," although if they do so, it will result in a significantly easier implementation.<br><br>2.Is it correct R1 assumes that a TSP can only have one methodology for the time frame specified in R2.1. Same for R2.2 and R2.3. They can be different for R2.1 and R2.2 or R2.3.<br>Response: R1 was not intended to be that restrictive. It has been reworded to clarify that one method must be used consistently for each path for each timeframe, but not for all paths for each timeframe.<br><br>3.The MOD-001-1 responsibilities of Transmission Operator are not fully clear. Is MOD-001-1 assuming that a Transmission Operator can calculate ATC based on his selected ATC Methodology for his Operator Area independent from TSP for purpose of evaluating some of his internal Service Requests and that TSP can have a different Methodology for the Tariff footprint that includes Operator Area of TOP. Meaning no relation between R1 and R2, TOP and TSP can have different methodologies for ATC Calculations.<br>Response: The SDT has clarified the standard to be clearer as follows: R2.Each Transmission Service Provider shall calculate ATC values for the time periods listed below using the ATC methodology or methodologies selected by their Transmission Operators.<br><br>R8<br>1.Is MOD -001-1 assuming that somehow the Transmission Operator is calculating TTC, AFC or ATC or any other data that will be used for purpose of evaluating Service Requests.<br>Response: It assumes that the Transmission Operator is determining TTC, as described in the individual methodology standards.<br>2. What is the list of assumptions that are referred to in R8.<br>Response: The Drafting Team could not develop a comprehensive, exclusive list of assumptions, but has added a partial list of examples in the measure, M6.<br><br>R10.13<br>1.If a TSP uses flow gate Methodology (MOD-030-1) what ETC need to be posted, the ETC on flow gate basis as specified in R7 MOD-030-1 or a ETC on path basis converted from ETC flow gate basis to ETC path basis using |

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| | conversion specified in R9 MOD-030-1.<br>Response: These standards do not address posting requirements.<br><br>2.Is it a correct assumption that ATC, ETC and TTC posted for a path can be values from 3 different constraints, so the numbers itself don't add up. Is this in line with what FERC had in mind when requesting posting of TTC, ATC and ETC.<br>Response: While it is possible that these numbers may not line up completely in all methodologies (i.e., Flowgate methodology due to ETC being determined on a Flowgate basis vs. ATC and TTC on a path basis), we don not believe this to be problematic. Note that these standards to not address posting requirements.<br><br>3.There are "rumors" that Scenario Analyzer is not considered being compliant by FERC with R10.3 standards . Are you aware of any additional NERC or NAESB requirements that describe what is considered being compliant with R10.13, posting ATC, ETC, TTC. Not the "what" requirement but the "how" requirement.<br>Response: These standards to not address posting requirements. It is the understanding of the drafting team that while FERC is not opposed to the use of Scenario Analyzer, they have not confirmed that it alone meets the posting requirements of Orders 889 or 890.<br><br>M2<br>1.Do we need to be compliant with the requirements of MOD-030 (selected ATC Methodology) or are we audit against the description of ATCID Document<br>Response: In cases where you are allowed to deviate from the standard, the requirements will indicate that implementing as defined in the ATCID is acceptable, and you will be measured against the ATCID.<br>M7<br>1. Same question as listed under R8.<br>Response: It assumes that the Transmission Operator is determining TTC, as described in the individual methodology standards.<br><br>MOD-004-1<br>R5<br>1.We think this should be a TSP responsibility and not a TP responsibility. What is reason this was assigned to Transmission Planner.<br>Response: The SDT believes the Transmission Planner is responsible based on the duration of the request (greater than one year).<br><br>MOD-008-1<br>R1 and R2<br>1.What is the reasoning behind making TSP responsible for the ATCID Document and CBMID document and making |

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| | TOP responsible for TRMID Document. We think TRMID should be a TSP responsibility also.<br>Response: The SDT believes the functional model assigns responsibilities like those described in the TRM standard to the Transmission Operator.<br>MOD-030-1<br>R2<br>1.What is the reasoning behind making TOP solely responsible to identify flow gates. We think both TSP and TOP are responsible, TOP for his Operating Area and TSP for the Tariff footprint and neighboring footprints.<br>Response: The SDT believes the functional model assigns this responsibility to the Transmission Operator.<br>R3<br>1.What is the reasoning behind making TOP responsible to maintain a transmission model to determine AFC. We think TSP should be responsible, to model the Tariff footprint and neighboring footprints as complete as possible.<br>Response: The SDT believes the functional model assigns this responsibility to the Transmission Operator.<br>R4.2<br>1.What is the reasoning behind requirement of higher granularity for AFC Calculations. (using Source and not POR). We think it should be allowed to calculate impacts on POR / POD basis (grouping of commonly dispatched resources within BA Area) and not with higher granularity. (Source) It is not required to schedule the Confirmed Reservation with same granularity.<br>Response: The standard has been modified to allow the flexibility requested.<br>2. What is meant with "interface points with adjacent TSP". The 1tier BA Area of TSP?<br>Response: The requirement has bee rewritten to more clearly refer to the first-tier Balancing Authority.<br><br>R5.2<br>1.What is definition of external (third party) flow gate. Is it something like: third party flow gate is flow gate for which the limiting equipment of the monitored element is not in one of the TOP Areas of the Tariff footprint of the TSP.<br>Response: R5.2 (now R5.3) was modified to remove third party and clarify language as "…Transmission Service Provider that calculates AFC for that Flowgate as the AFC."<br>2.What if RC footprint doesn't match the Tariff footprint. Are we required to use AFC overwrite from some one else if it is our RC flow gate however not our Tariff flow gate.<br>Response: Yes, if the flowgate meets the requirements provided by Old R5.2 now R5.3 as modified.<br><br>R6.2<br>1.What is the definition of "expected to be scheduled". Does this mean TSP can use judgment ?<br>Response: Yes, but note that the judgment that is used must be documented in the ATCID as required in R3.1 of MOD-001. For example, you may use seasonal or historical trends to guide expectations. |

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| | 2.What is the definition of "Included in the model ", probably refers to included in calculations referred to in R6.1.1 – R6.1.4<br>Response: This interpretation is correct.<br><br>R9<br>1.MOD-001-1 requires posting of ETC. If a TSP uses Flowgate Methodology does he need to convert ETC (flow gate based) to ETC (path based) using same formula as R9. Or does he need to post ETC flow gate based, result of R7 and R8 requirements of MOD-030-1.<br>Response: As stated in MOD-001 R10.13 the data can be shared in its present version. No conversion is necessary if it is requested.<br>M2<br>1. See R2 question.<br>Response: Please see response to R2 question.<br>M7<br>1. See R3 question.<br>Response: Please see response to R3 question.<br>M10<br>1. What about using outages for Monthly time frame? We only use outages if they last more than 15 days in that Month.<br>Response: MOD-001 now required that the ATCID specify outage processing rules for use when calculating ATC, |
| Response: | |
| Tacoma Power | 1) Tacoma Power supports the comments of the WECC MIC MIS ATC Drafting Team in regard to this question.<br><br>Please see responses to the WECC MIC MIS ATC Drafting Team.<br><br>2) In reference to MOD-030-1/R10, the requirement should be altered as follows: "The Transmission Service Provider shall [insert] provide a tool to [end insert] convert Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths. . . ." BPA calculates flowgate AFC's for its network and provides a tool for AFC-to-ATC conversion (in BPA's case, Power Utilization Factor Calculators). At this time, this is sufficient for transmission customer needs and that the posting of ATCs, as opposed to AFCs, would result in less transparency due to the sheer number of combinations that could be required to be posted.<br>Response: The standards do not preclude the use of a tool to create ATCs from AFCs; nor do they require the posting of ATCs. |
| Response: | |
| Tri-State Generation and Transmission Association | General comments:<br>Calculation and posting of hourly ATC will require knowledge of actual, preschedule, and real-time loads and other |

| Commenter | Other Comments |
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| | information. Tri-State is concerned that such information is to be shared only with TOs and other reliability entities, and encourages the drafting team to retain this limited distribution feature. On another level, compilation of this data comprises another set of confidential information the TO/TSP must track. These are now limited to transmission entities, but all it would take to violate confidentiality is one stroke of the pen - or one knowledgeable hacker.<br>Response: The SDT understands your concern, and expects entities to take appropriate steps to ensure such compromises do not occur.<br><br>The standard does not require validation. Tri-State finds that this may be a serious shortcoming of the proposed standards. Without some mechanism to verify actual flows from time to time, including loop-flow accommodation, the standards are nothing more than a documentation and data storage burden to utilities. It is difficult to imagine a simple validation method and process, but if there was one in place it might be possible to evaluate how accurate ATC values were after the fact.<br>Response: NERC will consider this suggestion in future work to the standards.<br><br>Related to this, no load-forecast probability level is specified for calculation of TRM/CBM/ETC. While we use low-exceedance probability forecasts for long-range transmission studies, this is not appropriate for short term ATC calculations. On the hourly time-frame, this would be manifested as load forecast bias. In other words, the firm ATC calculation process would naturally include some load margin to ensure that resulting ATC values will meet a defined risk level. Risk-level is a matter of company policy, so ATC will not necessarily be consistent from one utility to another. However, there should be a requirement to state the forecast probability level.<br>Response: The load forecast probability you describe is no longer intended to be incorporated within the ETC or CBM; it is to be accounted for in TRM. |
| Response: | |
| WECC MIC MIS ATC TF Drafting Team | AFFIRMATIVE COMMENTS:<br>The NERC Team and those listed above are reminded that the WECC MIC MIS ATC TF Drafting Team has solicited its responses face-to-face from 50+ individuals on 11/28/07 in Portland (attendance sheet retained by WECC and can be made available on request) and has also been supported by the ongoing technical support from the 40+ members of the WECC MIC MIS ATC Advisory Panel (16 separate entities) over the last year of drafting. As such, the WECC Team comments have been widely vetted and represent a substantial base of technical knowledge and veracity and are not merely the comments of a single entity.<br><br>The WECC Team and those listed above make the following “positive” proactive comments that the below listed features and attributes are essential to the standards as proposed and should be retained in the event a counter-position may be suggested by any singular entity.<br><br>GENERAL<br>1) The Team and those listed above support retention of the three methods recognizing the differences between the Rated System Path (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028). |

| Commenter | Other Comments |
|---|---|
| | 2) The Team and those listed above strongly support the retention of the proposed one-year implementation period.<br>3) The Team and those listed above support allowing NAESB to address all "posting" issues as they directly affect OASIS.<br><br>MOD-001 UMBRELLA<br>1) The Team and those listed above support allowing the use of more than one methodology for calculation of ATC by any one entity. For example, the Team supports allowing any entity to use the Flowgate methodology inside their affected area while also using the Rated System Path methodology at its boundaries.<br><br>2) The Team and those listed above support allowing each entity to specify in its ATCID how it will treat counterflows / schedules. (R4., R5.)<br><br>3) The Team and those listed above support the aggregation of transmission capacity for grandfathered contracts when shared with neighboring requestors.<br><br>4) The Team and those listed above support the specifically limited universe of entities to which data sharing is required as prescribed in R10.<br><br>5) The Team and those listed above are in support of changing the Violation Risk Factors as specifically commented on by SERC.<br><br>MOD-029 RATED SYSTEM PATH TTC, ETC & ATC<br>1) The Team and those listed above strongly support retention of the requirement(s) in R2.2 that accommodate paths which are "flow limited" by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing practices without re-inventing the wheel where no such effort is required to meet FERC's goals of transparency and consistency.<br><br>2) The Team and those listed above strongly support retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.<br><br>3) The Team and those listed above strongly support retention of the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.<br><br>4) The Team and those listed above strongly support retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts, associated litigation and potential renegotiation of associated operational agreements while supporting FERC's mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation methodologies is required. |

| Commenter | Other Comments |
| --- | --- |
| | 5) The Team and those listed above strongly support the adoption of a definition for counterflow to clarify its application in each equation.<br><br>MOD-004 CBM<br>1) The Team and those listed above support the concept of allowing the LSE to decide how much CBM it needs to satisfy its resource adequacy requirements and the TSP determining how the total CBM requirement for all requesting LSE's is allocated among paths. This is the proper division of labor.<br><br>2) The Team and those listed above strongly support allowing the LSE scheduling rights to the CBM after declaration of an EEA2 or higher condition.<br><br>MOD-30<br>1) The Team and those listed above support the MOD-30, R3 and R6 requirements only as to those sub-bullets addressing the most reasonable approach to how often information should be updated. |
| Response: Thank you for your supportive comments. | |
| WestConnect Transfer Capability Workgroup | In General the WestConnect Teams agrees with the WECC Comments. In addition the WestConnect Team adds the following comment.<br>Response: Please see responses to the WECC MIC MIS ATC Drafting Team.<br><br>Order 890 stresses transparency for ATC. The Team does not believe that Implementation Documents are transparent to the transmission users in that there are no requirements for the documents to be made available to the users. The WestConnect Team suggests that all the Implementation Documents be made public on the TSP's OASIS.<br>Response: NAESB will address OASIS posting requirements. |
| Response: Please see in-line responses. | |
| Western Area Power Administration – RMR | AFFIRMATIVE COMMENTS:<br>The NERC Team is reminded that the WECC MIC MIS ATC TF Drafting Team has solicited its responses face-to-face from 50+ individuals on 11/28/07 in Portland (attendance sheet retained by WECC and can be made available on request) and has also been supported by the ongoing technical support from the 43 members of the WECC MIC MIS ATC Advisory Panel (16 separate entities) over the last year of drafting. As such, the WECC Team comments have been widely vetted and represent a substantial base of technical knowledge and veracity and are not merely the comments of a single entity.<br>The WECC Team makes the following "positive" proactive comments that the below listed features and attributes should be retained in the event a counter-position may be suggested by any singular entity.<br>GENERAL<br>1) The Team supports retention of the three methods recognizing the differences between the Rated System Path |

| Commenter | Other Comments |
|---|---|
| | (MOD-029), Flowgate Methodology (MOD-030) and the Area Interchange Methodology (MOD-028).<br>2) The Team strongly supports the retention of the proposed one-year implementation period.<br>3) The Team supports allowing NAESB to address all "posting" issues as they directly affect OASIS.<br>MOD-001 UMBRELLA<br>1) The Team supports allowing the use of more than one methodology for calculation of ATC by any one entity. For example, the Team supports allowing any entity to use the Flowgate methodology inside their affected area while also using the Rated System Path methodology at its boundaries.<br>2) The Team supports allowing each entity to specify in its ATCID how it will treat counterflows / schedules. (R4., R5.)<br>3) The Team supports the aggregation of transmission capacity for grandfathered contracts when shared with neighboring requestors.<br>4) The Team supports the specifically limited universe of entities to which data sharing is required as prescribed in R10.<br>5) The Team supports those comments submitted by SERC specifying suggested changes to the VSLs. However, this Team makes no comment on the VSLs as they affect MOD-28.<br>Response: Please see responses to SERC comments.<br>MOD-029 RATED SYSTEM PATH TTC, ETC & ATC<br>1) The Team strongly supports retention of the requirement(s) in R2.2 that accommodate paths which are "flow limited" by allowing the rating in the flow limited direction to be equal to the rating in the reliability limited direction. This accommodates existing practices without re-inventing the wheel where no such effort is required to meet FERC's goals of transparency and consistency.<br>2) The Team strongly supports retention of the requirement(s) in R2.5 verifying that a given Posted Path does not adversely impact the TTC value of any existing path.<br>3) The Team strongly supports retention of the requirement(s) in R2.7 allowing the retention of existing and operationally proven TTCs without requiring a superfluous and redundant re-rating.<br>4) The Team strongly supports retention of the requirement(s) in R2.6 allowing for allocation of TTC via contract. This avoids the needless renegotiation of contracts, associated litigation and potential renegotiation of associated operational agreements while supporting FERC's mandate of transparency and consistency via MOD-01, R.3.6 wherein disclosure of allocation methodologies is required.<br>5) The Team strongly supports the adoption of a definition for counterflow to clarify its application in each equation."<br>MOD-004 CBM<br>1) The Team supports the concept of allowing the LSE to decide how much CBM it needs to satisfy its resource adequacy requirements and the TSP determining how the total CBM requirement for all requesting LSE's is allocated among paths. This is the proper division of labor.<br>2) The Team strongly supports allowing the LSE scheduling rights to the CBM after declaration of an EEA2 or higher condition.<br>MOD-30<br>1) The Team supports the MOD-30, R3 and R6 requirements as representing the most reasonable approach to |

| Commenter | Other Comments |
|---|---|
| | frequency of updating information. |
| Response: Thank you for your supportive comments.<br>Please see in-line responses. | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Flowgate:**

1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

**Available Flowgate Capability (AFC):** A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, and less a Transmission Reliability Margin.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system facilities removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs are used to determine Available Transfer Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**
2. **Number:** MOD-030-1
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
   - **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for ATC Paths.
   - **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate ATCs for ATC Paths.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID). [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- **R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
- **R1.2.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:
  - **R1.2.1.** Define if the source used for ATC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
  - **R1.2.2.** Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
  - **R1.2.3.** The source/sink or POR/POD identification and mapping to the model.
  - **R1.2.4.** If the Transmission Service Provider’s ATC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Identify Flowgates used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Element/Contingency combinations with an OTDF greater than 3% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.

**R2.1.2.** Results of a first contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements/Contingency combinations with an Outage Transfer Distribution Factor (OTDF) greater than 3% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.

**R2.1.3.** Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.

**R2.1.4.** Any limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.2.** At a minimum, update the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.

**R2.3.** At a minimum, update the list of Flowgates to create, modify, or delete external Flowgates that have been requested within thirty calendar days from the request.

**R2.4.** Determine the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, update the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the updated TFCs within seven calendar days of their determination.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains Facility Ratings specified by the Transmission Owners and Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and facilities161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include all expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the period calculated for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.3, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of base generation to load, for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed, based on:

**R6.1.1.** For on-peak intra-day and on-peak next-day AFCs:

6.1.1.1. Load forecast for the on-peak period calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load

6.1.1.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.2.** For off-peak intra-day and off-peak next-day AFCs:

6.1.2.1. Load forecast for the off-peak period calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load.

6.1.2.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.3.** For days two through 31AFCs:

6.1.3.1. Load forecast for the day calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load.

6.1.3.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.4.** For months two through 13 AFCs:

6.1.4.1. Load forecast for the month calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load.

6.1.4.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of base generation to load and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider’s area not included in the model.

**R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts, not included in the model and having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area not included in the model.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that are not included in the model and having a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled that are not included in the model for the Transmission Service Provider's area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that are not included in the model and have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that are not included in the model for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that are not included in the model and have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + Counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of Firm Transmission Service for that period, as defined in Business Practices.

**$Counterflows_{Fi}$** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + Counterflows$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Flowgate Capability for the ATC Path for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks$_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of Non-Firm Transmission Service for that period, as defined in Business Practices.

**Counterflows$_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC at a minimum on the following frequency: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R10.1.** For hourly AFC, once per day.

**R10.2.** For daily AFC, once per week.

**R10.3.** For monthly ATC, once a month.

**R11.** When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$TC = \min(P)$$

$$P = \{PTC_1, PTC_2, \ldots PTC_n\}$$

$$PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either ‘Available’ or ‘Total’).

**P** is the set of partial Transfer Capabilities (either available or total) for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or PTDF Flowgate.

**PTC$_n$** is the partial Transfer Capability (either ‘Available’ or ‘Total’) for a path relative to a Flowgate *n.*

**FC$_n$** is the Flowgate Capability (‘Available’ or ‘Total’) of a Flowgate *n*.

**DF$_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**M5.** The Transmission Operator shall provide evidence (such as data and models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs) that it updated the TFCs for each Flowgate at least once per calendar year. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

**M13.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ETC included the elements described in R6. (R6)

**M14.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ETC included the elements described in R7. (R7)

**M15.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm AFC used the algorithm and the elements described in R8 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R8)

**M16.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm AFC used the algorithm and the elements described in R9 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated ATC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Transfer Capabilities follows the procedure described in R11. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R6, R7, R8, R9, and R10 for the most recent calendar year plus current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications

- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2. | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2. |
| R2. | The Transmission Operator has not updated its list of external Flowgates for more than two consecutive quarters but not more than three consecutive quarters.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than three but not more than four consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of | The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than four but not more than five consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider | The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than five consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its list of internal Flowgates for two or more consecutive years.<br>**OR**<br>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.<br>**OR** |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | their determination, but is has not been more than 21 days (three weeks) since their determination. | with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. | The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination. |
| R3. | The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator did not update the Transmission model per the schedule specified in R3.<br>**OR**<br>The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>**OR**<br>The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>**OR**<br>The Transmission operator did |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | not include in the Transmission model detailed modeling data and topology at least three contiguous busses of the BES for more than one adjacent Reliability Coordinator area.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. |
| R4. | N/A | N/A | N/A | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not use the model provided by the Transmission Operator.<br>**OR**<br>The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.<br>**OR**<br>The Transmission Service provider did not use AFC |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | provided by a third party. |
| R6. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R6 when determining non-firm ETC, or used additional elements. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R7 when determining firm AFC, or used additional elements. |
| R8. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements. |
| R9. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R9. |
| R10 | For Hourly, the Transmission Service provider did not calculate for more than 24 hours but not more than 48 hours.<br>**OR**<br>For Daily, the Transmission Service provider did not calculate for more than 7 calendar days but not more than 14 calendar days.<br>**OR** | For Hourly, the Transmission Service provider did not calculate for more than 48 hours but not more than 72 hours.<br>**OR**<br>For Daily, the Transmission Service provider did not calculate for more than 14 calendar days but not more than 21 calendar days.<br>**OR** | For Hourly, the Transmission Service provider did not calculate for more than 72 hours but not more than 96 hours.<br>**OR**<br>For Daily, the Transmission Service provider did not calculate for more than 21 calendar days but not more than 28 calendar days. | For Hourly, the Transmission Service provider did not calculate for more than 96 hours.<br>**OR**<br>For Daily, the Transmission Service provider did not calculate for more than 28 calendar days<br>**OR**<br>For Monthly, the Transmission Service provider did not |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | For Monthly, the Transmission Service provider did not calculate for 31 or more calendar days, but less than 60 calendar days. | For Monthly, the Transmission Service provider did not calculate for 60 or more calendar days, but less than 90 calendar days. | **OR**<br>For Monthly, the Transmission Service provider did not calculate for 90 or more calendar days, but less than 120 calendar days. | calculate for 120 or more calendar days. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R11. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Flowgate:**

1.) A portion of~~designated point on~~ the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated ~~that will respect all~~ System Operating Limit~~s for that Flowgate~~.

**Available Flowgate Capability (AFC):** A measure of t~~T~~he flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, and less a Transmission Reliability Margin.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more ~~a specific~~ system ~~facility~~ facilities removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on ~~facility~~ Facility ~~ratings~~Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total ~~Transmission~~ Flowgate Capability to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs are used to determine Available Transfer ~~Transmission~~ Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-1**

3. **Purpose:** To increase consistency and ~~transparency~~ reliability in the development and documentation of transfer capability calculations for short-term ~~Transmission services~~use performed by entities using the Flowgate Methodology to support ~~reliable~~ analysis and system operations.

4. **Applicability:**

   **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for ATC ~~Posted~~ Paths.

   **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate ATCs for ~~Posted~~ ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that ~~all six (~~MOD-001-1, ~~MOD-004-1, MOD-008-1,~~ MOD-028-1, MOD-029-1 ~~,~~ and MOD-030-1~~)ATC-related standards~~ are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service ~~provider~~ Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID)~~the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations~~. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** -The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.2.1.** Define if the source used for ATC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generati~~on~~ors, the ATCID must identify how these generators participate in the group.~~.~~

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: ~~Lower~~Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Identify Flowgates ~~for~~ used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first C~~c~~ontingency transfer analysis for ATC Paths internal to a ~~t~~Transmission~~'s~~ O~~o~~perator's system up to the path capability such that at a minimum the first three limiting E~~e~~lement/C~~c~~ontingency combinations with an OTDF greater than 3% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.

~~**R1.1.1.** Any Facility within the Transmission Operator's area based on thermal, stability or voltage limits is a Flowgate.~~

**R2.1.2.** Results of a first c~~All first C~~ontingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements/Contingency combinations with an Outage Transfer Distribution Factor (OTDF) greater than 3% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use Contingency assumptions~~Contingencies~~ consistent with those~~the Contingencies~~ used in operations studies and planning studies for the applicable time periods.

**R2.1.3.** Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.~~OR~~ ~~any limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where~~

**R2.1.4.** Any limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or

- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.2.** At a minimum, update the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year~~quarter~~.

**R2.3.** At a minimum, update the list of Flowgates to create, modify, or delete external Flowgates that have been requested within thirty calendar days from the request.

**R2.4.** Determine the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, update the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the updated TFCs within seven calendar days of their determination.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a~~use a~~ Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains Facility Ratings specified by the Transmission Owners and Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and facilities161kV or below is allowed.

~~**R2.5.**~~Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination aAreas.~~for at least three contiguous busses of the Bulk Electric System directly and synchronously connected to the tie-lines into the systems of each adjacent Reliability Coordinator Area.~~

**R3.5.** ~~Contains modeling data and topology (or equivalent representation) for synchronous Facilities beyond three busses.~~

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows~~Use assumptions consistent with the assumptions used in operations studies and planning studies for the applicable time periods, including~~: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

~~**R3.1.**Contingencies.~~

~~**R3.2.**Modeling the impact of point-to-point reservations as follows:~~

- If the source, as specified in the ATCID, has been ~~specified~~ identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.

- If the source, as specified in the ATCID, has been identified~~specified~~ in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation~~modeled~~ in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified~~specified~~ in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation~~modeled~~ in the Transmission Service Provider's Transmission model, use the immediately~~interface point with the~~ adjacent Balancing Authority associated with the~~upstream~~ Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified~~specified,~~ in the reservation use the immediately ~~interface point with the~~ adjacent Balancing Authority associated with the~~upstream~~ Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified~~specified~~ in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified~~specified~~ in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation~~modeled~~ in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified~~specified~~ in the reservation and the point can~~-~~not be mapped to a discretely modeled point or an "equivalence" representation~~modeled~~ in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated~~interface point~~ with the ~~adjacent downstream~~ Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified ~~specified,~~ in the reservation use the immediately adjacent Balancing Authority associated ~~interface point~~ with the ~~adjacent downstream~~ Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

~~**R5.1.**~~**R5.2.** Include all expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the period calculated for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

~~**R5.2.**~~**R5.3.** For external ~~(third-party)~~ Flowgates, identified in R2.1.3, use ~~any~~ the AFC ~~for each specific Flowgate~~ provided by ~~that~~ the Transmission Service Provider that calculates AFC for that Flowgate~~third party as the AFC for that Flowgate~~.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of ~~F~~firm Network Integration Transmission~~and Native Load~~ Service, including the impacts of base generation to load, for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed, based on:

**R6.1.1.** For on-peak intra-day and on-peak next-day AFCs:

6.1.1.1. ~~Peak~~ Load forecast for the on-peak period calculated, consistent with that used for planning and operations for applicable time periods, including ~~native~~ Native ~~load~~ Load and network service ~~load~~ Load

6.1.1.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.2.** For off-peak intra-day and off-peak next-day AFCs:

6.1.2.1. ~~Peak~~ Load forecast for the off-peak period calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service ~~Load l~~Load-.

6.1.2.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.3.** For days two through 31AFCs:

~~6.1.3.1.1~~6.1.3.1. ~~Peak~~ Load forecast for the day calculated, consistent with that used for planning and operations for applicable time periods, including ~~native~~ Native ~~load~~ Load and network service ~~load~~ Load.

6.1.3.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.4.** For months two through 13 AFCs:

6.1.4.1. ~~Peak~~ Load forecast for the month calculated, consistent with that used for planning and operations for applicable time periods, including ~~native~~ Native ~~load~~ Load and network service ~~load~~ Load.

6.1.4.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of base generation to load and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**~~R6.2.~~R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area not included in the model.

**~~R6.3.~~R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts, not included in the model and haveing a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider ~~in excess of 3%~~ for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed. ~~The impact of any Grandfathered firm contracts expected to be scheduled for the Transmission Service Provider's area not included in the model.~~

**R6.5.** The impact of any Grandfathered firm obligations~~contracts~~ expected to be scheduled or expected to flow ~~not included in the model in excess of 3%~~ for ~~all adjacent~~the Transmission Service Provider's area not included in the model~~and any other Transmission Service Providers with which coordination agreements have been executed~~.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that are not included in the model and haveing a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

**~~R5.4.~~**

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled that are not included in the model for the Transmission Service Provider's area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that are not included in the model and have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

procedure used by the Transmission Service Provider~~in excess of 3%~~ for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that are~~contracts~~ not included in the model for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that are~~contracts~~ not included in the model ~~i~~and have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider~~n excess of 3%~~ for all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (~~i.e.,Secondary~~i.e., secondary ~~S~~service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

~~**R6.4.**~~

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC – ETC_{Fi} – CBM_i – TRM_i + Postbacks_{Fi} + Counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period~~,~~.

**TFC** is the Total Flowgate Capability of the Flowgate~~,~~.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period~~,~~.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period~~,~~.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period~~, ~~.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**Postbacks$_{Fi}$** are ~~adjustments~~ changes to firm AFC due to a change in the use of Firm Transmission Service~~postbacks~~ for that period, as defined in Business Practices~~, and~~.

**Counterflows$_{Fi}$** are adjustments to firm ~~ATC~~ AFC as determined by the Transmission Service Provider and ~~described~~ specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC – ETC_{Fi} – ETC_{NFi} – CBM_{Si} – TRM_{Ui} + Postbacks_{NFi} + Counterflows$$

**Where:**

**ATC$_{NF}$** is the non-firm Available Flowgate Capability for the ~~Posted~~ ATC Path for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC$_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**ETC$_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**CBM$_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**TRM$_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks$_{NF}$** are ~~adjustments~~ changes to non-firm Available Flowgate Capability due to ~~to~~ a change in the use of Non-Firm Transmission Service~~postbacks~~ for that period, as defined in ~~business~~ Business ~~practices~~Practices.

**Counterflows$_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and ~~described~~ specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC at a minimum on the following frequency: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R10.1.** For hourly AFC, once per day.

**R10.2.** For daily AFC, once per week.

**R10.3.** For monthly ATC, once a month.

**~~M1.~~R11.** When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values~~Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths~~ based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$\cancel{TC = \min\{PTC_1, PTC_2, \ldots PTC_n\} \text{ and } PTC_n =} \frac{FC_n}{DF_{np}}$$

$$TC = \min(P)$$

$$P = \{PTC_1, PTC_2, \ldots PTC_n\}$$

$$PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either 'Available' or 'Total').

**P** is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or PTDF Flowgate.

**$PTC_n$** is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n*.

**$FC_n$** is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

**$DF_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year~~quarter~~. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

~~**M4.**~~**M5.** The Transmission Operator shall provide evidence (such as data and models) that it determined the TFC for each Flowgate as defined in R2.~~3~~4. (R2.~~3~~4)

~~**M5.**~~**M6.** The Transmission Operator shall provide evidence (such as logs) that it updated the TFCs for each Flowgate at least once per calendar year. (R2.~~4~~5)

~~**M6.**~~**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.~~5~~6)

~~**M7.**~~**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M9.** ~~The Transmission Service Provider shall provide evidence (such as written documentation and studies) that the assumptions used in AFC calculation were consistent with those used in operations and planning studies for the same period. (R4.1)~~The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**~~M10.~~M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.~~1~~2)

**~~M11.~~M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.~~2~~3)

**~~M12.~~M13.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ETC included the elements described in R6. ~~and did not include any additional elements.~~ (R6)

**~~M13.~~M14.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ETC included the elements described in R7~~ and did not include any additional elements~~. (R7)

**~~M14.~~M15.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm AFC used the algorithm and the elements described in R8 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R8)

**~~M15.~~M16.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm AFC used the algorithm and the elements described in R9 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated ATC on the frequency defined in R10. (R10)

**~~M16.~~M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Transfer Capabilities follows the procedure described in R1~~0~~1. (~~R10~~R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2 and R3.

- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R6, R7, R8, R9, and R10 for the most recent calendar year plus current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2.<br>~~N/A~~ | The Transmission Service Provider does not include in its ATCID the ~~criteria for identifying Flowgates to be considered in AFC calculations.~~information described in R1.1 and R1.2. |
| R2. | The Transmission Operator has not updated its list of external Flowgates for more than two consecutive quarters but not more than three consecutive quarters.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than three but not more than four consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider | The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than four but not more than five consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>**OR**<br>The Transmission Operator | The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than five consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its list of internal Flowgates for two or more consecutive years.<br>**OR**<br>The Transmission Operator did not determine the TFC for a flowgate as described in |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination. | has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. | R2.~~3~~4.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination. |
| R3. | The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model~~ and one of those Facility Ratings was used (or should have been used) to establish a TFC for one or more flowgates~~.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model~~ and two to five of those Facility Ratings were used (or should have been used) to establish a TFC for one or more flowgates~~.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model~~ and six to ten of those Facility Ratings were used (or should have been used) to establish a TFC for one more flowgates~~.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator did not update the Transmission model per the schedule specified in R3.<br>**OR**<br>The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model~~ and eleven or more of those Facility Ratings were used (or should have been used) to establish a TFC for one or more flowgates~~.<br>**OR**<br>The Transmission operator did |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>**OR**<br>The Transmission operator did not include in the Transmission model detailed modeling data and topology at least three contiguous busses of the BES for more than one adjacent Reliability Coordinator area.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. |
| R4. | N/A | N/A | N/A | The Transmission Service Provider did not ~~use assumptions consistent with those used in operations and planning studies for the same period.~~represent the impact of Transmission Service as described in R4. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. ~~in the~~ | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.~~in the~~ | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.~~in the~~ | The Transmission Service Provider did not use ~~assumptions consistent with those used in operations and planning studies for the same period~~the model provided by the Transmission Operator.<br>**OR** |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | ~~AFC process.~~ | ~~AFC process.~~ | ~~AFC process.~~ | ~~The Transmission Service Provider did not model reservations as described in R4.1.~~<br>~~**OR**~~<br>The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.~~in the AFC process.~~<br>**OR**<br>The Transmission Service provider did not use AFC provided by a third party. |
| R6. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R6 when determining non-firm ETC, or used additional elements. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R7 when determining firm AFC, or used additional elements. |
| R8. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R9. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R9. |
| R10 | For Hourly, the Transmission Service provider did not calculate for more than 24 hours but not more than 48 hours.<br>**OR**<br>~~f~~For Daily, the Transmission Service provider did not calculate for more than 7 calendar days but not more than 14 calendar days.<br>**OR**<br>~~f~~For Monthly, the Transmission Service provider did not calculate for 31 or more calendar days, but less than 60 calendar days. | For Hourly, the Transmission Service provider did not calculate for more than 48 hours but not more than 72 hours.<br>**OR**<br>~~f~~For Daily, the Transmission Service provider did not calculate for more than 14 calendar days but not more than 21 calendar days.<br>**OR**<br>~~f~~For Monthly, the Transmission Service provider did not calculate for 60 or more calendar days, but less than 90 calendar days. | For Hourly, the Transmission Service provider did not calculate for more than 72 hours but not more than 96 hours~~,~~.<br>**OR**<br>~~f~~For Daily, the Transmission Service provider did not calculate for more than 21 calendar days but not more than 28 calendar days.<br>**OR**<br>~~f~~For Monthly, the Transmission Service provider did not calculate for 90 or more calendar days, but less than 120 calendar days. | For Hourly, the Transmission Service provider did not calculate for more than 96 hours.<br>**OR**<br>~~f~~For Daily, the Transmission Service provider did not calculate for more than 28 calendar days.<br>**OR**<br>~~f~~For Monthly, the Transmission Service provider did not calculate for 120 or more calendar days. |
| ~~R10~~R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in ~~R10~~R11. |

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# Implementation Plan for Standard MOD-030-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary


As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-030-1, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining ATC.


## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard incorporates the following requirements from FAC-012-1:

– R1 (Documentation of the Transfer Capability Methodology)

– R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

– R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013-1:

– R1 (Calculation of the Transfer Capabilities)

– R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-030-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted second first for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30 Day posting before board adoption. | March 7, 2008 |
| 5. Board adopts MOD-001-1. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Rated System Path Methodology:** The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

## A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

**R1.1.1.** Includes at least:

1.1.1.1. The Transmission Operator area.

1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area.

1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement.

**R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.

**R1.1.3.** Models all generation Facilities larger than 20 MVA in the studied area.

**R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the ATCID.

**R1.1.5.** Uses Load forecast by Balancing Authority.

**R1.1.6.** Uses Transmission Facility additions and retirements.

**R1.1.7.** Uses Generation Facility additions and retirements.

**R1.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

**R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

**R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

**R2.** The Transmission Operator shall use the following process to determine TTC: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

**R2.1.1.** When modeling normal conditions, do not model any Transmission Element above 100% of its continuous rating.

**R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

**R2.1.3.** Uncontrolled separation shall not occur.

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction.

**R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

**R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** Verify that the TTC for the ATC Path being studied does not adversely impact the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

**R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NL_F$** is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$NITS_F$** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_F$** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_{NF}$** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + Counterflows_F$$

**Where**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm Available Transfer Capability due to a change in the use of Firm Transmission Service for that period, as defined in Business Practices.

**$Counterflows_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

**R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC – ETC_F – ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + Counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Transfer Capability due to a change in the use of Non-Firm Transmission Service for that period, as defined in Business Practices.

**$Counterflows_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC used in its ATC calculations, as required in R1. (R1)

**M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (R1.1)

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

**M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

**M7.** Each Transmission Service Provider shall produce the algorithms it used to calculate ETCs for Firm and Non-Firm Transmission Service, as required in R5 and R6, showing that only the variables allowed in R5 and R6 were used to calculate ETCs. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R5 and R6)

**M7.1.** Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ETCs in R5 and R6. (R5 and R6)

**M8.** Each Transmission Service Provider shall produce the algorithms it used to calculate firm and non-firm ATCs, as required in R7 and R8, showing that only the variables allowed in R7 and R8 were used to calculate ATCs. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R7 and R8)

**M8.1.** Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ATCs in R7 and R8. (R7 and R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R5, R6, R7 and R8. (M7 and M8)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator met all but one of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator met all but two of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator met all but three of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator did not meet four or more of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. |
| R2 | N/A | N/A | N/A | The Transmission Operator did not calculate TTC using the process described in R2. |
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 1 ATC Path OR more than 0% but less than 1% of all ATC Paths | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 2 ATC Paths OR 1% or more but less than 2% of all ATC Paths. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 3 ATC Paths OR 2% or more but less than 5% of all ATC Paths. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in or any associated SOL, for the larger of 4 or more ATC Paths OR 5% or more of all ATC Paths. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider 28 or more calendar days after the report was finalized. |
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R5 when determining firm ETC, or used additional elements. |
| R6. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R6 when determining non-firm ETC, or used additional elements. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements. |
| R8. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted second first for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30 Day posting before board adoption. | March 7, 2008 |
| 5. Board adopts MOD-001-1. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Rated System Path Methodology:** The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC to derive Available ~~Transmission~~ Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

## A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-1**

3. **Purpose:** To increase consistency and reliability~~transparency~~ in the development and documentation of transfer capability calculations for short-term use ~~Transmission services~~ performed by entities using the Rated System Path Methodology to support analysis and~~reliable~~ system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths~~Posted Paths~~.

   **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths~~Posted Paths~~.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that ~~all six (~~MOD-001-1, ~~MOD-004-1, MOD-008-1,~~ MOD-028-1, MOD-029-1, and MOD-030-1~~)ATC-related standards~~ are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** When calculating TTCs for ATC Paths~~Posted Paths~~, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria: ~~[*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]~~

**~~R1.1.~~R1.1.1.** Includes at least:

~~R1.1.1.~~1.1.1.1. The Transmission Operator ~~Area~~area.

~~R1.1.2.~~1.1.1.2. All Transmission Operator ~~Areas~~ areas contiguous with its own Transmission Operator ~~Area~~ area.

~~R1.1.3.~~1.1.1.3. Any other Transmission Operator ~~Area~~ area linked to the Transmission Operator's ~~Area~~ area by joint operating agreement.

**~~R1.2.~~R1.1.2.** Models all system ~~elements~~ Elements as in-service for the assumed initial conditions.

**~~R1.3.~~R1.1.3.** Models all generation Facilities larger than 20 MVA in the studied area.

**~~R1.4.~~R1.1.4.** Models phase shifters in ~~Non~~non-regulating mode, unless otherwise specified in the ATCID.

~~**R1.1.5.**Uses current Facility Ratings as provided by the Transmission Owner and Generator Owner~~

**~~R1.6.~~R1.1.5.** Uses ~~peak l~~Load forecast by Balancing Authority.

**~~R1.7.~~R1.1.6.** Uses Transmission Facility additions and retirements.

**~~R1.8.~~R1.1.7.** Uses Generation Facility additions and retirements.

~~R1.9.~~**R1.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

~~R1.10.~~**R1.1.9.** Models series compensation for each ~~“Extra High Voltage (EHV)”~~ line at the expected operating level unless specified otherwise in the ATCID.

~~R1.11.~~**R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

~~**R1.1.12.** Where three phase fault damping is used to determine stability limits, identifies the percent used and includes justification for use unless specified otherwise in the ACTID.~~

~~Each of the entities identified in R1.1.1 have reviewed and accepted the model as accurately representing their system.~~

**R2.** The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or ~~(~~reliability limit) that can be simulated on the ATC Path ~~Posted Path~~ while at the same time satisfying all planning criteria ~~for N-0, N-1, and N-2~~ contingencies as follows:

**R2.1.1.** When modeling normal conditions ~~(N-0)~~, do not model any Transmission Element above 100% of its continuous rating.

**R2.1.2.** When modeling ~~N-1 or N-2~~ contingencies~~,~~ the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its ~~emergency~~ Emergency ~~rating~~Rating.

~~**R2.1.3.** Do not exceed any Facility Ratings (including thermal and voltage ratings)~~

~~R2.1.4.~~**R2.1.3.** Uncontrolled separation shall not occur.

~~**R2.1.5.** Initiate system disturbances for stability studies by a three-phase-to-ground fault on all modeled “Extra High Voltage (EHV)” buses adjacent to the major interconnection point of the modeled Posted Path.~~

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current ~~transmission~~ Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction.

**R2.3.** For an ATC Path ~~Posted Path~~ whose capacity is limited by contract, set TTC on the ATC Path ~~Posted Path~~ at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R~~1.~~2.1.

**R2.4.** For an ATC Paths~~Posted Paths~~ whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** Verify that the TTC for the ~~Posted Path~~ATC Path being studied does not adversely impact the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path,~~Posted Path,~~ allocate TTC of that ATC Path~~Posted Path~~ in accordance with the contractual agreement made by the multiple owners of that ATC Path~~Posted Path~~.

**R2.7.** For ATC Paths ~~Posted Paths~~ whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken~~and the Regional Entity has not taken action~~ to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. —[*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**~~R3.~~R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path~~Posted Path~~, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path~~Posted Path~~.

~~**R4.**Each Transmission Operator shall establish the TTC at the lesser of the TTC calculated in MOD-029-1 or any System Operating Limit for that Posted Path. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]~~

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for an ATC Path~~a Posted Path~~, the Transmission Service Provider shall use the ~~following~~ algorithm below: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NL_F$** is the firm capacity set aside ~~reserved~~ to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth,~~ and losses~~ not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$NITS_F$** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and ~~load~~ Load growth, ~~and losses~~ not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_F$** is the firm capacity set aside ~~reserved~~ for grandfathered ~~Firm~~ Transmission Service and ~~bundled~~ contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service~~,~~.

**$ROR_F$** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for an ATC Path ~~a Posted Path~~ the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside ~~reserved~~ for Network Integration Transmission Service serving Load (i.e., ~~S~~secondary s~~S~~ervice), ~~,~~ to include losses, and load growth~~, and losses~~ not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_{NF}$** is the non-firm capacity set aside ~~reserved~~ for grandfathered Transmission Service and ~~bundled~~ contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**R7.** When calculating f~~F~~irm ATC for an ATC Path ~~a Posted Path~~ for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + Counter\cancel{schedule}flows_F$$

**Where**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path ~~Posted Path~~ for that period.

**TTC** is the Total Transfer Capability of the ATC Path ~~Posted Path~~ for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path ~~Posted Path~~ during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path ~~Posted Path~~ during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path ~~Posted Path~~ during that period.

**$Postbacks_F$** are ~~adjustments~~ changes to firm Available Transfer Capability due to a change in the use of Firm Transmission Service~~postbacks~~ for that period, as defined in ~~business~~ Business P~~p~~ractices.

**Counter~~schedules$_F$~~ flows$_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and ~~described~~ specified in their ~~Available Transfer Capability Implementation Document.~~ ATCID.

**R8.** When calculating non-firm ATC for an ATC Path ~~Posted Path~~ for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counter$flows~~-schedules~~$_{NF}$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path ~~Posted Path~~ for that period.

**TTC** is the Total Transfer Capability of the ATC Path ~~Posted Path~~ for that period.

**$ETC_F$** is the sum of existing ~~non-~~firm commitments for the ATC Path ~~Posted Path~~ during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the ATC Path ~~Posted Path~~ during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path ~~Posted Path~~ that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path ~~Posted Path~~ that has not been released for sale -(unreleased) as non-firm capacity by the Transmission Service Provider during that period~~,~~.

**$Postbacks_{NF}$** are ~~adjustments~~ changes to non-firm Available Transfer Capability due to a change in the use of Non-Firm Transmission Service~~postbacks~~ for that period, as defined in B~~b~~usiness P~~p~~ractices~~, and~~.

**Counter~~-sche~~flows~~dules~~$_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and ~~described~~ specified in its ~~Available Transfer Capability Implementation Document.~~ATCID.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any~~each~~ Transmission model it used to calculate TTC for purposes of -calculating ~~posting~~ ATC for each ATC Path~~Posted Path~~, as required in R1, for the time horizon(s) to be examined. (R1)

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC used in its ~~posted~~ATC calculations, as required in R1. (R1)

~~M1.2.~~The Transmission model produced must include the areas listed ~~show the use of each attribute specified~~ in R1.1.1 (R1.1)~~; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred.~~

**M1.2.**

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.~~1~~1~~10~~2; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

~~**M1.3.**~~**M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)~~the entities identified in R1.1.1 have reviewed the~~

~~model and agree with the accuracy of the representation of their system. Entities that have elected to not review the model shall be assumed to have~~

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (~~See~~ R1.1.4, R.1.1.~~10~~9, and R1.1.10~~1 and R1.12~~).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. -(R2.7)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

~~**M3.**Each Transmission Operator that uses the Rated System Path Methodology shall produce the source documents reflecting the values it used to meet the requirements in R1.1.5 through R1.1.9 for the period examined. (R1)~~

~~**M4.**Each Transmission Operator that uses the Rated System Path Methodology shall produce the models, reports, or study results that it used to establish TTC in accordance with R2.1 through R2.78. (R2)~~

~~**M5.**Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)~~

~~Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)~~

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (~~R3~~R4)

~~**M7.**Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R.1.2 for each~~ ATC Path~~Posted Path, 2) Any corresponding SOLs for those~~ ATC Path~~Posted Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R6~~ R7~~and R7~~ R8 ~~for each~~ ATC Path~~Posted Path. (R4)~~

**M7.** Each Transmission Service Provider shall produce the algorithms it used to calculate ETCs for Firm and Non-Firm Transmission Service, as required in R5 and R6, showing that only the variables allowed in R5 and R6 were used to calculate ETCs. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R5 and R6)

~~M8.~~

**~~M8.1.~~M7.1.** Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ETCs in R5 and R6. (R5 and R6)

**~~M9.~~M8.** Each Transmission Service Provider shall produce the algorithms it used to calculate f~~F~~irm and n~~N~~on-f~~F~~irm ATCs, as required in R7 and R8, showing that only the variables allowed in R7 and R8 were used to calculate ATCs. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R7 and R8)

~~M9.1.~~M8.1. Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ATCs in R7 and R8. (R7 and R8)

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Data Retention**

- The Transmission Operator shall have its latest models used to determine TTC ~~and evidence of previous versions~~ for R1. (M1~~ and M6~~)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- ~~The Transmission Operator shall retain the latest version and the prior version of the source documents used to update its models to show compliance with R1. (M3)~~
- ~~The Transmission Operator shall retain evidence to show compliance with R2.1 through R2.7 8 for the most recent three calendar years plus the current year. (M4)~~
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (~~M5~~M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with ~~R1,~~ R3 and R4. (~~M6~~ M5 and ~~M7~~M6)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R5, R6, R7 and R8. (~~M8~~ M7 and ~~M9~~M8)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits

- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator met all but one of the modeling requirements specified in R1.1<br>~~**OR**~~<br>~~The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and one of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths~~.<br>**OR**<br>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator met all but two of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~**OR**~~<br>~~The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and two to five of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths.~~ | The Transmission Operator met all but three of the modeling requirements specified in R1.1.<br>**OR**<br>~~**OR**~~<br>~~The Transmission Operator failed to demonstrate that one of the affected parties identified in R1.1.1 .~~The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~ and six to ten of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths.~~ | The Transmission Operator did not meet four or more of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~**OR**~~<br>~~The Transmission Operator failed to demonstrate that two or more of the affected parties identified in R1.1.1 The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and eleven or more of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths.~~ |
| R2 | N/A | N/A | N/A | The Transmission Operator did not calculate TTC using the |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | process described in R2. |
| ~~R3.~~<br>~~R4~~R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 1 ATC Path OR more than 0% but less than 1% of all ATC Paths ~~The Transmission Operator provided the TTC and study report to the Transmission Service Provider after more than seven, but not more than 14 calendar days after the report was finalized.~~<br>~~N/A~~ | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 2 ATC Paths OR 1% or more but less than 2% of all ATC Paths.~~The Transmission Operator provided the TTC and study report to the Transmission Service Provider after more than 14, but not more than 21 calendar days after the report was finalized.~~<br>~~N/A~~ | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 3 ATC Paths OR 2% or more but less than 5% of all ATC Paths.~~The Transmission Operator provided the TTC and study report to the Transmission Service Provider after more than 21, but not more than 28 calendar days after the report was finalized.~~<br>~~The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated the SOL for one to four Posted PathsATC Paths.~~ | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in or any associated SOL, for the larger of 4 or more ATC Paths OR 5% or more of all ATC Paths. ~~The Transmission Operator provided the TTC and study report to the Transmission Service Provider 28 or more calendar days after the report was finalized.~~<br>~~The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in or any associated the SOL, for five or more Posted PathsATC Paths.~~ |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider 28 or more calendar days after the report was finalized. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R5 when determining f~~F~~irm ETC, or used additional elements. |
| R6. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R6 when determining n~~N~~on-f~~F~~irm ETC, or used additional elements. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R7 when determining f~~F~~irm ATC, or used additional elements. |
| R8. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R8 when determining n~~N~~on-f~~F~~irm ATC, or used additional elements. |

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# Implementation Plan for Standard MOD-029-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-029-1, which describes the Rated System Path methodology for determining ATC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard incorporates the following requirements from FAC-012-1:

– R1 (Documentation of the Transfer Capability Methodology)

– R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

– R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013-1:

– R1 (Calculation of the Transfer Capabilities)

– R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-029-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

## A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining TTC: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

**R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

**R1.3.** Any contractual obligations for allocation of TTC.

**R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.

**R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.5.1.** Define if the source used for ATC calculations is obtained from the source field or the POR field of the transmission reservation

**R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the POD field of the transmission reservation

**R1.5.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.5.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

**R2.** When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities161kV or below is allowed.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs (for intra-day and next-day) for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R3.1.** For on-peak intra-day TTCs, and on-peak next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R3.1.2.** Load forecast for the on-peak period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For off-peak intra-day and off-peak next-day TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

**R3.2.2.** Load forecast for the off-peak period being calculated.

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.** When calculating TTCs (for time periods beyond next day) for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** For days two through 31 TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R4.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R4.1.2.** Load forecast for the day being calculated.

**R4.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.2.** For months two through 13 TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R4.2.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R4.2.2.** Load forecast for the month calculated.

**R4.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R5.** When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** Use all Contingencies meeting the criteria described in its ATCID.

**R5.2.** Respect any contractual allocations of TTC.

**R5.3.** Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate

representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

**R6.** Each Transmission Operator shall calculate TTC for each ATC Path as defined below, unless otherwise requested by the Transmission Service Provider: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** At least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations.

**R6.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R6.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer in duration.

**R7.** Each Transmission Operator shall calculate TTC for each ATC Path using the following process: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R7.1.** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

**R7.2.** If the limit in step R7.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R7.3.** Use (as the TTC) the lesser of:

- The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or
- The sum of Facility Ratings of all ties comprising the ATC Path.

**R7.4.** For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed that Transmission Operator's contractual rights.

**R8.** The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R8.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

**R8.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

**R9.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NITS_F$** is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_F$** is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the

[1] The Transmission operator may honor distribution factors less than 5% if desired.

effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R10.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_{NF}$** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R11.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + Counterflows_F$$

**Where:**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm ATC due to a change in the use of Firm Transmission Service for that period, as defined in Business Practices.

**$Counterflows_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

**R12.** When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + Counterflows_{NF}$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm ATC due to a change in the use of Non-Firm Transmission Service for that period, as defined in Business Practices.

**$Counterflows_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3) (R4)

**M4.** Each Transmission Operator shall provide the contingencies used in determining TTC and its ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R5)

**M5.** Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R5.2. (R5)

**M6.** Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R5.3, and that estimated scheduled interchange was included in the determination of TTC. (R5)

**M7.** Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to calculate TTCs at specific intervals) that TTCs have been calculated at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R6.(R6)

**M8.** Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R7. (R7)

**M9.** Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R8. (R8)

**M10.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ETC used the algorithm and elements described in R9 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R9)

**M11.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ETC used the algorithm and the elements described in R10 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R10)

**M12.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ATC used the algorithm and the elements described in R11 and does not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R11)

**M13.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ATC used the algorithm and the elements described in R12 and does not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R12)

## D. Compliance

### 1. Compliance Monitoring Process

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset**

Not applicable.

**1.3. Data Retention**

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 and R4 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R5, R6, R7 and R8 for the most recent12 months.
- The Transmission Service Provider shall retain evidence to show compliance with R9, R10, R11 and R12 for the most recent12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has an ATCID that meets the intent of Requirement 1 but the ATCID is missing some minor information. | The Transmission Service Provider has an ATCID but it is missing one of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing two of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing three or more of the four required elements in R1. |
| R2. | The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>**OR**<br>The Transmission Operator did not include in the Transmission model modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator area.<br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>**OR**<br>The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator area.<br>**OR**<br>The Transmission Operator did not include in the Transmission model modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator areas.<br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | modeled. |
| R3. | The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID.. | The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.. | In calculating TTCs for intra-day and next-day, the Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.<br>**OR**<br>In calculating TTCs for intra-day and next-day, the Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3.1. |
| R4. | N/A | N/A | N/A | In calculating TTCs for time periods beyond next day, the Transmission Operator did not include more than fifty expected generation and Transmission outages, additions or retirements in the TTC process.<br>**OR**<br>In calculating TTCs for time periods beyond next-day, the Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R4.1. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R5. | N/A | N/A | N/A | The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br>**OR**<br>The Transmission Operator did not respect contractual allocations of TTC.<br>**OR**<br>The Transmission Operator did not model reservations' sources or sinks as described in R5.3<br>**OR**<br>The Transmission Operator did not use firm reservations to estimate interchange or did not utilize that estimate in the TTC calculation as described in R5.3. |
| R6. | N/A | N/A | N/A | The Transmission Operator did calculated TTCs in excess of the minimum time frames specified in R6. |
| R7. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the process specified in R7. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R8. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.<br>**OR**<br>The Transmission Operator t provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination<br>**OR**<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations.<br>**OR**<br>The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination<br>**OR**<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations. |
| R9. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R9 when determining firm ETC, or used additional elements. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R10. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R10 when determining non-firm ETC, or used additional elements. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R11 when determining firm ATC, or used additional elements. |
| R12. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R12 when determining non-firm ATC, or used additional elements. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes ~~the modifications identified in the SAR with~~ consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

## A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and ~~transparency~~ reliability in the development and documentation of ~~T~~transfer ~~C~~capability calculations for short-term ~~Transmission services~~ use performed by entities using the Area Interchange Methodology to support ~~reliable~~ analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ~~Posted~~ ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ~~Posted~~ ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that ~~all six (~~MOD-001-1, ~~MOD-004-1, MOD-008-1,~~ MOD-028-1, MOD-029-1, and MOD-030-1~~) ATC-related standards~~ are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining TTC: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations ~~may~~ can be validated.

**R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

**R1.3.** Any contractual obligations for allocation of TTC.

**R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.

**R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.5.1.** Define if the source used for ATC calculations is obtained from the source field or the POR field of the transmission reservation

**R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the POD field of the transmission reservation

**R1.5.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.5.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

**R2.** When calculating TTC for ~~Posted~~ ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities161kV or below is allowed.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs (for intra-day and next-day~~-~~) for ~~Posted~~ ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's ~~Area~~area.~~,~~ The Transmission Operator shall also include~~all~~ the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers~~,~~ and ~~any of the following data provided by~~ any other Transmission Service Providers with which coordination agreements have been executed:~~.,~~ ~~provided that data can be associated with Facilities that are explicitly represented in the Transmission model:~~ [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R3.1.** For on-peak intra-day TTCs, and on-peak next-day ~~intra-peak~~ TTCs, use the following (a~~t a minimum~~s well as any other values and additional parameters as specified in the ATCID):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R3.1.2.** ~~Peak~~ Load forecast for the on-peak period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For off-peak intra-day and off-peak next-day TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID~~at a minimum~~):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

**R3.2.2.** ~~Peak~~ Load forecast for the off-peak period being calculated.

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.** When calculating TTCs (for time periods beyond next day) for ~~Posted~~ ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's a~~A~~rea. The Transmission Operator shall also include~~, all~~ the following data associated with Facilities that are explicitly represented in the Transmission model as provided by adjacent Transmission Service Providers~~,~~ and any ~~of the following data provided by any~~ other Transmission Service Providers with which coordination agreements have been executed~~, provided that data can be associated with Facilities that are explicitly represented in the Transmission model~~: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** For days two through 31 TTCs, use the following (a~~t a minimum~~s well as any other values and additional parameters as specified in the ATCID):

**R4.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R4.1.2.** ~~Peak~~ Load forecast for the day being calculated.

**R4.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.2.** For months two through 13 TTCs, use the following (a~~t a minimum~~s well as any other values and additional parameters as specified in the ATCID):

**R4.2.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R4.2.2.** ~~Peak~~ Load forecast for the month calculated.

**R4.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R5.** When calculating TTCs for ~~Posted~~ ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** Use all Contingencies meeting the criteria described in its ATCID.

**R5.2.** Respect any contractual allocations of TTC.

**R5.3.** Include, for each time period, the ~~expected schedules using monthly or longer~~ F~~f~~irm Transmission ~~s~~Service expected to be scheduled as specified in the ATCID~~,~~ (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers)~~,~~ for the Transmission Service Provider~~'s Area~~, all adjacent Transmission

Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been ~~specified~~ identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been ~~specified~~ identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" ~~modeled~~ in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been ~~specified~~ identified in the reservation and the point cannot be mapped to a discretely modeled point ~~or~~ , an "equivalence," or an "aggregate representation" ~~modeled~~ in the Transmission Service Provider's Transmission model, use the ~~interface point with the adjacent upstream~~immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been ~~specified~~identified in the reservation, use the immediately adjacent Balancing Authority associated with the ~~interface point with the adjacent upstream~~ Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, -has been ~~specified~~ identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, -has been ~~specified~~ identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation"~~modeled~~ in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, -has been ~~specified~~ identified in the reservation and the point can not be mapped to a discretely modeled point ~~or~~, an "equivalence," or an "aggregate representation" ~~modeled~~ in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the ~~interface point with the adjacent downstream~~ Transmission Service Provider to which the power is to be delivered as the sink.
- If the sink, as specified in the ATCID, -has not been ~~specified~~identified in the reservation, use the immediately adjacent Balancing Authority associated with the ~~interface point with the adjacent downstream~~ Transmission Service Provider to which the power is being delivered as the sink.

**R6.** Each Transmission Operator shall calculate TTC for each ~~Posted~~ ATC Path as defined below, unless otherwise requested by the Transmission Service Provider: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** At least once ~~per~~in the calendar week prior to the specified period for TTCs used in hourly~~,~~ and daily ATC calculations.

**R6.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R6.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer in duration.

**R7.** Each Transmission Operator shall calculate TTC for each ~~Posted~~ ATC Path using the following process: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R7.1.** Determine the incremental Transfer Capability for each ~~Posted~~ ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- ~~-~~A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is ~~greater than~~ 5% or greater[1].
-

**R7.2.** If the limit in step R7.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R7.3.** ~~Sum the incremental Transfer Capability and all impacts of Firm Transmission Service that were included in the study model~~Use (as the TTC) the lesser of:

– The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or

– The sum of Facility Ratings of all ties comprising the ~~Posted~~ ATC Path.

**R7.4.** For ~~Posted~~ ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed that Transmission Operator's contractual rights.

[1] The Transmission operator may honor distribution factors less than 5% if desired.

**R8.** The Transmission Operator shall provide the Transmission Service Provider of that ~~Posted~~ ATC Path with the most current value for TTC for that ~~Posted~~ ATC Path no more than: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R8.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

**R8.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

~~**R7.1.** within seven calendar days of its determination.~~

**R9.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for an ~~Posted~~ ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NITS_F$** is the firm capacity ~~reserved~~ set aside for Network Integration Transmission Service ~~reserved~~ (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ~~Posted~~ ATC Paths that serve as interfaces with other ~~Transmission Service Providers~~Balancing Authorities.

**$GF_F$** is the firm capacity ~~reserved~~ set aside for Grandfathered Firm Transmission Service and ~~bundled~~ contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts ~~on~~ from other ~~Posted~~ ATC Paths of the Transmission Service Provider as ~~described~~ specified in the ATCID.

**R10.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for an ~~Posted~~ ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**NITS$_{NF}$** is the non-firm capacity ~~reserved~~ set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ~~Posted~~ ATC Paths that serve as interfaces with other ~~Transmission Service Providers~~Balancing Authorities.

**GF$_{NF}$** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and ~~bundled~~ contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**PTP$_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**OS$_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from ~~on~~ other ATC~~Posted~~ Paths of the Transmission Service Provider as ~~described~~ specified in the ATCID.

**R11.** When calculating ~~F~~firm ATC for an ~~Posted~~ ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + Counterflows_F$$

**Where:**

**ATC$_F$** is the firm Available Transfer Capability for the ~~Posted~~ ATC Path for that period~~,~~.

**TTC** is the Total Transfer Capability of the ~~Posted~~ ATC Path for that period~~,~~.

**ETC$_F$** is the sum of existing firm Transmission commitments for the ~~Posted~~ ATC Path during that period~~,~~.

**CBM** is the Capacity Benefit Margin for the ~~Posted~~ ATC Path during that period~~,~~.

**TRM** is the Transmission Reliability Margin for the ~~Posted~~ ATC Path during that period~~,~~ .

**Postbacks$_F$** are ~~adjustments~~ changes to firm ATC due to a change in the use of Firm Transmission Service~~postbacks~~ for that period, as defined in Business Practices~~, and~~.

**Counterflows$_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and ~~described~~ specified in the~~ir~~ ATCID.

**R12.** When calculating ~~N~~non-~~F~~firm ATC for a ~~Posted~~ ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + Counterflows_{NF}$$

**Where:**

**ATC$_{NF}$** is the non-firm Available Transfer Capability for the ~~Posted~~ ATC Path for that period~~,~~.

**TTC** is the Total Transfer Capability of the ~~Posted~~ ATC Path for that period~~,~~.

**ETC$_{F}$** is the sum of existing firm Transmission commitments for the ~~Posted~~ ATC Path during that period~~,~~.

**ETC$_{NF}$** is the sum of existing non-firm Transmission commitments for the ~~Posted~~ ATC Path during that period~~,~~.

**CBM$_{S}$** is the Capacity Benefit Margin for the ~~Posted~~ ATC Path that has been scheduled without a separate reservation ~~on~~ during that period~~,~~.

**TRM$_{U}$** is the Transmission Reliability Margin for the ~~Posted~~ ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period~~,~~ .

**Postbacks$_{NF}$** are ~~adjustments~~ changes to non-firm ATC due to a change in the use of Non-Firm Transmission Service~~postbacks~~ for that period, as defined in Business Practices~~, and~~.

**Counterflows$_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and ~~described~~ specified in the~~ir~~ ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** Each~~The~~ Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** Each~~The~~ Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3) (R4)

**M4.** Each~~The~~ Transmission Operator shall provide the contingencies used in determining TTC and its ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R5)

**M5.** Each~~The~~ Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R5.2. (R5)

**M6.** Each~~The~~ Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that ~~monthly or longer~~firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R5.3, and that estimated scheduled interchange was included in the determination of TTC. (R5)

**M7.** Each~~The~~ Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to calculate TTCs at specific intervals) that TTCs have been calculated at least once ~~per~~ in the calendar week prior to the specified period for TTCs used in hourly~~,~~ and daily ATC calculations, ~~and~~ at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R6.(R6)

**M8.** Each~~The~~ Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R7. (R7)

**M9.** Each ~~The~~ Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it~~s~~ provided its Transmission Service Provider with the most current values for TTC in accordance with R8. (R8)

**M10.** Each~~The~~ Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of f~~F~~irm ETC used the algorithm and elements described in R9 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R9)

**M11.** Each~~The~~ Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of n~~N~~on-f~~F~~irm ETC used the algorithm and the elements described in R10 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R10)

**M12.** Each~~The~~ Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of ~~F~~firm ATC used the algorithm and the elements described in R11 and does not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R11)

**M13.** Each~~The~~ Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of n~~N~~on-f~~F~~irm ATC used the algorithm and the elements described in R12 and does not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R12)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 and R4 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R5, R6, R7 and R8 for the most recent12 months.
- The Transmission Service Provider shall retain evidence to show compliance with R9, R10, R11 and R12 for the most recent12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has an ATCID that meets the intent of Requirement 1 but the ATCID is missing some minor information. | The Transmission Service Provider has an ATCID but it is missing one of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing two of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing three or more of the four required elements in R1. |
| R2. | The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission or Generation~~or~~ Owner in their Transmission model~~ and one of those Facility Ratings was used (or should have been used) to establish TTC for one or more Posted ATC Paths~~. ~~An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized.~~<br><br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generation~~or~~ Owner in their Transmission model~~ and two to five of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted ATC Paths~~. ~~An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized.~~<br><br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generation~~or~~ Owner in their Transmission model~~ and six to ten of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted ATC Paths~~. ~~An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized.~~<br><br>**OR**<br><br>The Transmission Operator did not include in the Transmission model modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator area.<br><br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been | The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission or Generation~~or~~ Owner in their Transmission model~~ and eleven or more of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted ATC Paths~~. ~~An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized.~~<br><br>**OR**<br><br>The Transmission Operator's model ~~did not include in the Transmission model~~ includes equivalent representation of non-radial facilities greater than 161 kV ~~detailed modeling data and topology~~ for its own Reliability Coordinator area.<br><br>**OR**<br><br>The Transmission Operator did |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | <u>modeled.</u> | not include in the Transmission model ~~detailed~~ modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator areas.<br><br><u>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled.</u> |
| R3. | The Transmission Operator did not include <u>in the TTC process</u> one to ten expected generation and Transmission outages, additions or retirements <u>as specified in the ATCID.</u>~~in the TTC process.~~ | The Transmission Operator did not include <u>in the TTC process</u> eleven to twenty-five expected generation and Transmission outages, additions or retirements <u>as specified in the ATCID.</u>~~in the TTC process~~. | The Transmission Operator did not include <u>in the TTC process</u> twenty-six to fifty expected generation and Transmission outages, additions or retirements <u>as specified in the ATCID.</u>~~in the TTC process~~. | In calculating TTCs for intra-day and next-day, the Transmission Operator did not include <u>in the TTC process</u> more than fifty expected generation and Transmission outages, additions or retirements <u>as specified in the ATCID.</u> ~~in the TTC process.~~<br><br>**OR**<br><br>In calculating TTCs for intra-day and next-day, the Transmission Operator did not include the ~~peak~~ Load forecast or unit commitment in its TTC calculation as described in R3.1. |
| R4. | N/A | N/A | N/A | In calculating TTCs for time periods beyond next day, the Transmission Operator did not include more than fifty expected generation and Transmission outages, additions or retirements in the TTC process. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | **OR**<br>In calculating TTCs for time periods beyond next-day, the Transmission Operator did not include the ~~peak~~ Load forecast or unit commitment in its TTC calculation as described in R4.1. |
| R5. | N/A | N/A | N/A | The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br>**OR**<br>The Transmission Operator did not respect contractual allocations of TTC.<br>**OR**<br>The Transmission Operator did not model reservations' sources or sinks as described in R5.3<br>**OR**<br>The Transmission Operator did not use ~~monthly or longer~~ firm reservations to estimate interchange or did not utilize that estimate in the TTC calculation as described in R5.3. |
| R6. | N/A | N/A | N/A | The Transmission Operator did ~~not~~ calculated TTCs ~~per the~~in excess of the minimum time frames specified in R6. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R7. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the ~~minimum time frames~~process specified in R7. |
| R8. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.<br>**OR**<br>The Transmission Operator ~~has no~~t provided its Transmission Service Provider with its ~~Posted ATC~~ Path TTCs used in monthly ATC calculations ~~within~~ more than seven calendar days ~~of~~ after their determination, but ~~is has~~ not ~~been~~ more than 14 calendar days since their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ~~Posted ATC~~ Path TTCs used in monthly ATC calculations ~~within~~more than 14 calendar days after~~of~~ their determination, but ~~is has~~ not been more than 21 calendar days ~~since~~ after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ~~Posted ATC~~ Path TTCs used in monthly ATC calculations ~~within~~more than 21 calendar days after~~of~~ their determination, but ~~is has~~ not been more than 28 calendar days ~~since~~ after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination<br>**OR**<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations.<br>**OR**<br>The Transmission Operator ~~has not~~ provided its Transmission Service Provider with its ~~Posted ATC~~ Path TTCs used in monthly ATC calculations ~~within~~ more than 28 ~~or more~~ calendar days ~~of~~ after their determination<br>**OR**<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R9. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R9 when determining firm ETC, or used additional elements. |
| R10. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R10 when determining non-firm ETC, or used additional elements. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R11 when determining firm ATC, or used additional elements. |
| R12. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R12 when determining non-firm ATC, or used additional elements. |

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# Implementation Plan for Standard MOD-028-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-028-1, which describes the Area Interchange methodology (previously referred to as the Network Response ATC methodology) for determining ATC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

## Modified Standards

This standard incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-028-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30 Day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Transmission Reliability Margin Implementation Document (TRMID):** A document that describes the implementation of a Transmission Reliability Margin methodology.

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**
2. **Number:** **MOD-008-1**
3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.
4. **Applicability:**
   - **4.1.** Transmission Operator.
   - **4.2.** Transmission Service Provider.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in calculating TRM, and a description of how that component is used to calculate a TRM value:

- Aggregate Load forecast uncertainty (not included in determining generation reliability requirements for CBM).
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve sharing requirements.
- Inertial response and frequency bias.

**R1.2.** A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in the Transmission planning process for the time period studied .

**R1.3.** The description of the method used to allocate TRM across ATC Paths or Flowgates.

**R1.4.** The identification of the TRM calculation used for the following time periods:

**R1.4.1.** Same day and real-time.

**R1.4.2.** Day-ahead and pre-schedule.

**R1.4.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

**R1.5.** If TRM is not used, a statement of that practice.

**R2.** Each Transmission Operator shall only use the components of uncertainty from R1.1 to calculate TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.** Each Transmission Operator shall make available its TRMID, and any underlying documentation, work papers and load flow base cases used to determine TRM, to any of the following who make a written request no more than 30 calendar days after receiving the request. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Operators

**R4.** Each Transmission Operator using TRM shall recalculate TRM values in accordance with the TRMID at least once every 13 months. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R5.** The Transmission Operator using TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after they change. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

## C. Measures

**M1.** Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, and CBMID , or other evidence, (such as written documentation, study reports, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** Each Transmission Operator shall provide a dated copy of any request for its TRMID or associated documentation, and evidence such as copies of emails or postal receipts that show the recipient, date and contents as evidence that the requested documentation was provided within the specified timeframe to the entities described in R3. (R3)

**M4.** Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it recalculated TRM values at least once every thirteen months for each of the TRM time periods. (R4)

**M5.** Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago. | The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.<br>**OR**<br>The Transmission Operator's TRMID does not address one of the sub requirements. | The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.<br>**OR**<br>The Transmission Operator's TRMID does not address two or three of the sub requirements. | The Transmission Operator has a TRMID that does not incorporate changes that have been made more than one year ago.<br>**OR**<br>The Transmission Operator does not have a TRMID;<br>**OR**<br>The Transmission Operator's TRMID does not address 4 or more of the sub requirements. |
| R2. | N/A | N/A | N/A | The Transmission Operator included elements of uncertainty not defined in R1 in their calculation of TRM.<br>**OR**<br>The Transmission Operator included components of CBM in TRM. |
| R3. | The Transmission Operator provided the TRMID to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days. | The Transmission Operator provided the TRMID to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days. | The Transmission Operator provided the TRMID to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days. | The Transmission Operator did not provide the TRMID for 90 days or more. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R4 | N/A | The Transmission Operator did not determine TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago. | The Transmission Operator determined TRM 15 months ago or more, but not more than 18 months ago. | The Transmission Operator did not determine TRM<br>OR<br>The last determination of TRM was 18 months ago or more. |
| R5 | The Transmission Operator did provide the TRM to all entities specified in more then 7 days but less than 14 days. . | The Transmission Operator did provide the TRM to all entities specified in 14 days or more, but less than 30 days. | The Transmission Operator did provide the TRM to all entities specified in 30 days or more, but less than 60 days. | The Transmission Operator did not provide the TRM to all entities specified within 60 days of the change. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes ~~the modifications identified in the SAR with~~ consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30 Day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Transmission Reliability Margin Implementation Document (TRMID): ** A document that describes the implementation of a Transmission Reliability Margin methodology.

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**
2. **Number:** **MOD-008-1**
3. **Purpose:** To promote the consistent and ~~transparent~~ reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to ~~ensure~~ support ~~reliable~~ analysis and system operations.
4. **Applicability:**
   - **4.1.** Transmission Operator.
   - **4.2.** Transmission Service Provider.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date ~~that all six (MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, MOD-030-1)ATC-related standards are~~this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date th~~e set of~~is standard~~s~~ is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** Identification of (on each of its respective ~~Posted~~ ATC Paths or Flowgates) each of the following components of uncertainty if used in calculating TRM, and a description of how that component is used to calculate a TRM value:

- Aggregate Load forecast uncertainty (not included in determining generation reliability requirements for CBM).
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve sharing requirements.
- Inertial response and frequency bias.

**R1.2.** A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in ~~any associated~~

~~operations studies or~~the Transmission planning ~~studies~~process for the ~~corresponding~~ time period studied .

~~**R1.2.**periods.~~

**R1.3.** The description of the method used to allocate~~of~~ TRM ~~allocation~~ across ATC~~Posted~~ Paths or Flowgates.

**R1.4.** The identification of the TRM calculation used for the following time periods:

**R1.4.1.** Same day and real-time.

**R1.4.2.** Day-ahead and pre-schedule.

**R1.4.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

**R1.5.** If TRM is not used, ~~zero for all the time periods listed in R1.4,~~ a statement of that practice.

**R2.** ~~The~~ Each Transmission Operator shall only use the components of uncertainty from R1.1 to calculate TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. ~~Transmission capacity required for the period immediately following a contingency and up to 59 minutes following the contingency is included in TRM.~~ [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.** Each Transmission Operator shall make available ~~provide~~ its TRMID, and any underlying documentation, work papers and load flow base cases used to determine TRM, to any~~all~~ of the following who make a written ~~within seven calendar days of a~~ request no more than 30 calendar days after receiving the request. ~~:~~ [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- ~~The Transmission Service Provider responsible for tariff administration over the Facilities operated by the Transmission Operator~~
- ~~The Reliability Coordinator responsible for oversight of the Facilities for which the Transmission Service Provider offers service.~~
- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Operators

~~**R4.**Each Transmission Service Provider shall make available within seven calendar days of a documented request for such information the TRMIDs used by its Transmission Operator(s), and any underlying documentation, work papers and load flow base cases used to determine TRM, to Transmission Service Providers who have made a request for such information. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]~~

~~**R5.** Each Transmission Operator shall calculate, at least once every 13 months (in accordance with the definitions in its TRMID), a TRM value for the following time periods (on each Posted Path or Flowgate) and shall provide these TRM values to its Transmission Service Provider(s) and Transmission Planner(s) within seven calendar~~

~~days of the calculation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]~~

~~**R5.1.**R4.1 Same day and real-time.~~

~~**R5.2.**R4.2 Day-ahead and pre-schedule.~~

**R4.** Each Transmission Operator using TRM shall recalculate TRM values in accordance with the TRMID at least once every 13 months. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R5.** The Transmission Operator using TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after thei~~r~~y changi~~ng~~e. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

## C. Measures

**M1.** Each~~The~~ Transmission ~~Service Provider~~Operator shall produce its ~~current~~ TRMID evidencing inclusion of all specified information ~~described~~ in ~~R1to show its compliance with~~ R1. ~~.~~(R1)

**M2.** ~~The~~ Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, and CBMID, or other evidence, (such as written documentation, study reports, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** ~~The~~ Each Transmission Operator shall provide a dated copy of any request for its TRMID or associated documentation, and evidence such as copies of emails or postal receipts that show the recipient, date and contents as evidence that the requested documentation was provided within the specified timeframe to the entities described in R3. (R3)

~~**M4.**The Transmission Service Provider shall provide a dated copy of any request for its Transmission Operator's TRMID or associated documentation, and evidence such as copies of emails or postal receipts that show the recipient, date and contents as evidence that the requested documentation was provided within the specified timeframe to the requesting entity as described in R4. (R4)~~

~~**M5.**The Transmission Operator shall provide evidence (such as logs and data that it determined TRM at least once every thirteen months for each of the listed time periods and provided it to their Transmission Service Provider(s) and Transmission Planner(s) as described in R5. (R5)~~

**M4.** ~~The~~Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it recalculated TRM values at least once every thirteen months for each of the TRM time periods. (R4)

**M5.** ~~The~~Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago. | The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.<br>**OR**<br>The Transmission Operator's TRMID does not address one of the sub requirements. | The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.<br>**OR**<br>The Transmission Operator's TRMID does not address two or three of the sub requirements. | The Transmission Operator has a TRMID that does not incorporate changes that have been made more than one year ago.<br>**OR**<br>The Transmission Operator does not have a TRMID;<br>**OR**<br>The Transmission Operator's TRMID does not address 4 or more of the sub requirements. |
| R2. | N/A | N/A | N/A | The Transmission Operator included elements of uncertainty not defined in R1 in their calculation of TRM.<br>**OR**<br>The Transmission Operator ~~or it~~ included components of CBM in TRM. |
| R3. | The Transmission Operator ~~did~~ provided the TRMID to ~~all~~ a requesting ~~entities~~ entity specified in R3 but provided TRMID ~~to all parties~~ in more than ~~7~~30 days but less than ~~14~~?45 days. ~~.~~ | The Transmission Operator provided the TRMID to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days.~~The Transmission Operator did not provide the TRMID to one entities specified in R3~~<br>~~**OR**~~ | The Transmission Operator provided the TRMID to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days.~~The Transmission Operator did not provide the TRMID to two entities specified in R3~~<br>~~**OR**~~ | The Transmission Operator did not provide the TRMID for 90 days or more.~~The Transmission Operator did not provide the TRMID to any of the entities specified in R3~~<br>~~**OR**~~<br>~~provided TRMID to all parties in more than 60 days.~~<br>~~Failed to provide the TRMID~~ |

| | | | | |
|---|---|---|---|---|
| | | ~~provided TRMID to all parties in more than 14 ? days or more but less than ?30 days. .~~ | ~~provided TRMID to all parties in more than 30 ? days or more but less than ?60 days.~~ | ~~within ? Days.~~ |
| ~~R4.~~<br>~~R5~~<br>R4 | ~~The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in more than 7 calendar days but no more than 14 days of a request by a Transmission Service Provider.~~<br>~~The Transmission Operator did not provide the Transmission Planner with its determined TRM values.~~<br>N/A | ~~The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in more than 14 calendar days but no more than 30 days of a request by a Transmission Service Provider.~~<br>~~The Transmission Operator did not determine TRM for any of the listed time frames within thirteen months of the previous determination, and the last determination was not more than 15 months ago.~~<br>The Transmission Operator did not determine TRM ~~for any of the listed time frames~~ within thirteen months of the previous determination, and the last determination was not more than 15 months ago. | ~~The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in more than 30 calendar days but no more than 60 days of a request by a Transmission Service Provider.~~<br>~~The Transmission Operator did not determine TRM for any of the listed time frames within thirteen months of the previous determination, and the last determination was more than 15 months ago, but not more than 18 months ago.~~<br>~~**OR**~~<br>~~The Transmission Operator did not provide the Transmission Service Provider with its determined TRM values, and one or more of those values changed by more than twenty percent from the previous value given to the Transmission Service Provider.~~<br>The Transmission Operator ~~did not~~ determined TRM ~~for any of the listed time frames within thirteen months of the previous~~ | ~~The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in 60 days or more of a request by a Transmission Service Provider Or did not make the current TRMID available.~~<br>~~The Transmission Operator did not determine TRM for any of the listed time frames within thirteen months of the previous determination, and the last determination was more than 18 months ago.~~<br>~~**OR**~~<br>~~The Transmission Operator has not provided the Transmission Service Provider with any determined TRM values.~~<br>The Transmission Operator did not determine TRM<br>OR~~for any of the listed time frames within thirteen months of the previous determination,~~<br>~~and t~~The last determination of TRM was ~~more than~~ 18 months |

| | | | | |
|---|---|---|---|---|
| | | | ~~determination, and the last determination was more than~~ 15 months ago or more, but not more than 18 months ago. | ago or more. |
| R5 | The Transmission Operator did provide the TRM to all entities specified in more then 7 days but less than 14 days. . | The Transmission Operator did provide the TRM to all entities specified in 14 days or more, but less than 30 days. | The Transmission Operator did provide the TRM to all entities specified in 30 days or more, but less than 60 days. | The Transmission Operator did not provide the TRM to all entities specified within 60 days of the change. |

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Implementation Plan for Standard MOD-008-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-008-1, which describes the reliability aspects of determining and maintaining a Transmission Reliability Margin and what components of uncertainty may be considered when making that determination.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes MOD-008-1. MOD-009-0 has been incorporated into this standard, made irrelevant by this standard, or is being addressed by the North American Energy Standards Board, and should be retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-008-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes the modifications with consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Generation Capability Import Requirement (GCIR):** The amount of generation capability from external sources requested by a Load-Serving Entity (LSE) (or group of LSEs with an aggregated need for Capacity Benefit Margin) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.

**Capacity Benefit Margin Implementation Document (CBMID):** A document that describes the implementation of a Capacity Benefit Margin methodology.

**Planned Resource Sharing Group (PRSG):** A group of Load-Serving Entities who have agreed to jointly meet their resource adequacy requirements.

## A. Introduction

1. **Title:** **Capacity Benefit Margin**

2. **Number:** **MOD-004-1**

3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.

4. **Applicability:**

   **4.1. Functional Entity:**

   **4.1.1** Load-Serving Entity.

   **4.1.2** Planned Resource Sharing Group.

   **4.1.3** Transmission Service Providers that maintain CBM.

   **4.1.4** Balancing Authority.

   **4.1.5** Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM.

5. **Facility Limitations/Specifications:**

   **5.1.** None.

6. **Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard become effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service Provider shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

**R1.1.** Its procedure for a Load-Serving Entity or Planned Resource Sharing Group within a Balancing Authority associated with the Transmission Service Provider to request the Generation Capability Import Requirement (GCIR) including the disposition and handling of deficient requests.

**R1.2.** Its procedure and assumptions for setting CBM for each ATC Path or Flowgate based on Load-Serving Entity or Planned Resource Sharing Group GCIR.

**R1.3.** Its procedure to request the use of Transfer Capability set aside as CBM.

**R1.4.** A statement of whether the Transmission Service Provider allows ATC or AFC to be less than zero due to CBM.

**R2.** The Transmission Service Provider shall make available its CBMID and any changes to the CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area prior to the effective date of a change. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.** A Load-Serving Entity or Planned Resource Sharing Group that wants Transfer Capability to be set aside in the form of CBM shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

**R3.1.** Submit an annual GCIR request to the Transmission Service Provider and Transmission Planner per the specifications in the CBMID that includes:

**R3.1.1.** The GCIR, specifying:

3.1.1.1. A monthly GCIR value for each month for the next 24 months. If monthly values are not a requirement as per the applicable reserve margin and resource adequacy requirements documented in R3.1.2, a yearly GCIR value for the current and following year will be sufficient .

3.1.1.2. An annual GCIR value for each subsequent year for each Balancing Authority or Posted Path not to exceed 10 years into the future.

3.1.1.3. The location of the load served by the GCIR (e.g., Balancing Authority, zones, markets …).

3.1.1.4. Assumed external resources (e.g., Balancing Authority(ies), specific generators, markets …) from which generation supporting each GCIR value of 3.1.1.1 and 3.1.1.2 will be supplied or the specific ATC Paths to be used for import of the generation supporting the GCIR.

**R3.1.2.** Identification of all applicable reserve margin and resource adequacy requirements, and the entity(ies) responsible for establishing them, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities.

3.1.2.1. The process and periodicity of calculating or recalculating GCIR if the entities specified in R3.1.2 require calculating GCIR on a frequency different than specified in R3.1.1

**R3.1.3.** A summary of the results of resource studies performed to determine the amount of the request, not to include confidential information.

**R3.1.4.** All resource studies (and supporting information) performed to determine the amount of the request.

**R3.2.** Every thirty-one calendar days, each Load Serving Entity or Planned Resource Sharing Group shall adjust its GCIR request, if necessary per 3.1.1 or 3.1.2.1, to reflect any incremental increase or decrease in required GCIR by either simple adjustment or through recalculation. .

**R3.3.** Base the request provided per R3.1 on studies conducted in accordance with verifiable historical, state, regional transmission organization or regional entity criteria.

**R4.** Within fourteen calendar days of receiving a request or change to a GCIR request that meets the requirements defined in R3.1, the Transmission Service Provider shall set the CBM for the next 13 months requested as described in R3.1 as follows: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Determine the amount of CBM (for use in R4.2) for each request by using one of the following:

**R4.1.1.** For the Area Interchange Methodology and the Rated System Path Methodology, using the requested Generation Capability Import Requirement for the appropriate ATC Path(s)

**R4.1.2.** For the Flowgate Methodology, determining the significant impacts of each request on each Flowgate

4.1.2.1. Determine impacts of a request by multiplying the requested GCIR by the Distribution Factor for the import relative to the Flowgate or model the GCIR explicitly in the AFC model per R3.1.1.3 and R3.1.1.4.

**R4.2.** For the Area Interchange Methodology and the Rated System Path Methodology, set CBM for each ATC Path equal to the sum of all requests such that all requests can be met simultaneously or all firm ATC has been allocated to CBM as follows:

**R4.2.1.** If the situation exists where there is insufficient capability on the ATC Path to satisfy the sum of all GCIR requests and the Transmission Service Provider, per R1.4, does not allow ATC to be less than zero, then the Transmission Service Provider shall set the CBM such that the monthly ATCs equal zero

**R4.2.2.** If the situation exists where there is insufficient capability on the ATC Path to satisfy the sum of all GCIR requests and the Transmission Service Provider, per R1.4, allows the ATC to be less than zero, then the Transmission Service Provider shall set the CBM equal to the sum of the requested GCIR for that ATC Path.

**R4.3.** For the Flowgate Methodology set CBM for each Flowgate equal to the sum of all requests on that Flowgate such that all requests can be met simultaneously or all firm ATC has been allocated to CBM as follows:

**R4.3.1.** If the situation exists where there is insufficient Flowgate AFC to satisfy the sum of all GCIR requests and the Transmission Service Provider, per R1.4, does not allow the Flowgate AFC to be less than zero, then the Transmission Service Provider shall set the CBM such that the monthly Flowgate AFCs equal zero

**R4.3.2.** If the situation exists where there is insufficient Flowgate AFC to satisfy the sum of all GCIR requests and the Transmission Service

Provider, per R1.4, allows the Flowgate AFC to be less than zero, then the Transmission Service Provider shall set the CBM equal to the sum of the requested GCIR for that Flowgate.

**R5.** Within sixty calendar days of receiving a request or change to a GCIR request that meets the requirements defined in R3.1, the Transmission Planner shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** As per R3.1.1.3 and R3.1.1.4, model the GCIR explicitly in the ATC/AFC model or use the CBM calculated using requirements R4.1 through R4.3 for all years requested beyond 13 months not to exceed 10 years

**R5.2.** If so requested, provide the Transmission Service Provider with the following:

**R5.2.1.** The total amount of CBM for each ATC Path or Flowgate on the Transmission Service Provider's system in each of the years specified in the original CBM request not to exceed 10 years.

**R5.2.2.** If less than the sum of all requests was established as the CBM for any period, for each ATC Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the years specified in the original request not to exceed 10 years.

**R6.** Within seven calendar days of the determination of CBM as described in R4 or R5, the Transmission Service Provider shall provide each Load-Serving Entity or Planned Resource Sharing Group that requested CBM and the Balancing Authority hosting its (their) load with a report that includes: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** The total amount of CBM for each ATC Path or Flowgate on the Transmission Service Provider's system in each of the months or years specified in the original request.

**R6.2.** If less than the sum of all requests was established as the CBM for any period:

- For each ATC Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the months and years specified in the original request
- The option to pursue alternatives, including expansion, with the Transmission Service Provider.

**R7.** The Transmission Service Provider and Transmission Planner shall each provide copies of the supporting data, including any models, used for allocating CBM over each ATC Path or Flowgate to the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

**R7.1.** Each of its associated Transmission Operators within thirty calendar days of their making a request for the data.

**R7.2.** To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, or Planning Coordinator within thirty calendar days of their making a request for the data.

**R8.** The Load-Serving Entity or Balancing Authority that wants to schedule energy over firm Transfer Capability set aside as CBM shall submit an Arranged Interchange, and shall not request to schedule energy over firm Transfer Capability set aside as CBM unless experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. *[Violation Risk Factor: Lower] [Time Horizon: Same-day Operations]*

**R9.** When reviewing an Arranged Interchange using CBM, the Balancing Authority and Transmission Service Provider shall waive, within the bounds of reliable operation, any real-time timing and ramping requirements. *[Violation Risk Factor: Lower] [Time Horizon: Same-day Operations]*

**R10.** The Transmission Service Provider shall approve any Arranged Interchange using CBM that is submitted by an Energy Deficient Entity[1] under an EEA2 if the CBM is available. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

## C. Measures

**M1.** Each Transmission Service Provider shall produce its CBMID evidencing inclusion of all information specified in R1. (R1)

**M2.** Each Transmission Service Provider shall have evidence (such as dated logs and data, copies of dated electronic messages, or other equivalent evidence) to show that prior to the effective date of a change to its CBMID, it made the CBMID available to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators specified in R2. (R2)

**M3.** Each Load-Serving Entity or Planned Resource Sharing Group that wants CBM shall provide a copy of its GCIR request with the supporting information specified in R3.1 to show that it is compliant with R3.1. (R3)

**M4.** Each Load-Serving Entity or Planned Resource Sharing Group that requests changes to its GCIR as per R3.2 shall provide dated copies of its updated GCIR along with studies or documentation of the changes that support its request; such as Transmission Service Requests, generator outage reports, and load-forecast changes that affect its resource adequacy requirements documented in R3.1.2. (R3).

**M5.** Each Load-Serving Entity or Planned Resource Sharing Group that wants CBM shall provide evidence (such as studies, historical data, copies of state or regional transmission organization reliability criteria, regional generation reliability criteria or other equivalent evidence) that it has based its GCIR request on verifiable historical, state, regional transmission organization, or regional generation reliability criteria in accordance with R3.3. (R3)

**M6.** Each Transmission Service Provider shall provide evidence including copies of GCIR requests and requests for GCIR changes and other evidence such as copies of the actual computations to set CBM, or other equivalent evidence to show that CBM for the months requested as described in R3.1.1 has been established using the process described in R4. (R4)

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[1] See Attachment 1-EOP-002-0 for definition.

**M7.** Each Transmission Planner shall provide evidence including copies of GCIR requests and requests for GCIR changes and other evidence (such as written documentation of studies and supporting study models that model base load flow, copies of actual computations to set CBM, or other equivalent evidence) to show that the GCIR has been used to either model GCIR or calculate as per the process described in R5. (R5)

**M8.** Each Transmission Service Provider shall provide copies of the reports sent to Load-Serving Entities and Balancing Authorities along with other evidence (such as logs and data, copies of electronic messages, or other equivalent evidence) to show that within seven calendar days of the determination of CBM, a report meeting the requirements described in R6 was provided as specified. (R6).

**M9.** Each Transmission Service Provider and Transmission Planner shall each provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in R7. (R7)

**M10.** Each Load-Serving Entity that scheduled energy over firm Transfer Capability set aside as CBM shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time they requested the schedule using CBM, they were in an EEA2. (R8)

**M11.** Each Balancing Authority and Transmission Service Provider shall provide evidence (such as operating logs and tag data) that it waived real-time timing and ramping requirements when approving an Arranged Interchange using CBM (R9)

**M12.** Each Transmission Service Provider shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any Arranged Interchange using CBM for any Energy Deficient Entity[2] where the total CBM available was greater than the amount of CBM requested in the Arranged Interchange. (R10)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority (CEA)

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall maintain its current, in force CBMID and any prior versions of the CBMID that were in force since the last compliance audit to show compliance with R1.

[2] See Attachment 1-EOP-002-0 for definition.

- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7 and R10 for the most recent three calendar years plus the current year.
- The Load-Serving Entity and Planned Resource Sharing Group shall each maintain evidence to show compliance with R3, and R8 for the most recent three calendar years plus the current year.
- The Transmission Planner shall maintain evidence to show compliance with R5 and R7 for three calendar years.
- The Balancing Authority shall maintain evidence to show compliance with R9 for three calendar years.
- If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

**None.**

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made within the last three months. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago.<br>**OR**<br>The Transmission Service Provider's CBMID does not address one of the sub requirements. | The Transmission Service Provider has CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago.<br>**OR**<br>The Transmission Service Provider's CBMID does not address two of the sub requirements. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made more than twelve months ago.<br>**OR**<br>The Transmission Service Provider does not have a CBMID;<br>**OR**<br>The Transmission Service Provider's CBMID does not address three or more of the sub requirements. |
| R2. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator 14 or more calendar days but not more than 30 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator 30 or more calendar days but not more than 60 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator 60 or more calendar days but not more than 90 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator more than 90 calendar days after a change was made. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit the information required by any one of the following: R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 20MW or 10%, whichever is smaller, and not more than 30MW or 20%, whichever is smaller. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit the information two or more of the following: R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 30MW or 20%, whichever is smaller, and not more than 40MW or 30%, whichever is smaller. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not include one or more of the items specified in R3.1.1 in its request.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit any of the information described in R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 40MW or 30%, whichever is smaller.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group requested GCIR greater than its needs for imports to meet reserve margin or resource adequacy requirements (not to include the incremental power flows from reserve sharing requirements), and the additional GCIR |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | requested was more than 10MW in excess of the needed amount. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | N/A | N/A | The Transmission Service Provider set CBM for the months requested as described in R4 more than 14, but not more than 30 calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Service Provider did not follow the process described in R4. | The Transmission Service Provider set CBM for the months requested as described in R4 more than 30 calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Service Provider did not follow the process described in R4 and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met. |
| R5. | N/A | N/A | The Transmission Planner set CBM for the years requested as described in R5 more than 60, but not more than 120, calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Planner did not follow the process described in R5. | The Transmission Planner set CBM for the years requested as described in R5 more than 120 calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Planner did not follow the process described in R5, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met. |
| R6. | The Transmission Service Provider provided the report to the requesting entities in more than 7 calendars days but not more than 9 calendar days of determining the CBM | The Transmission Service Provider provided the report to the requesting entities in 9 or more calendar days but not more than 14 calendar days of determining CBM | The Transmission Service Provider provided the report to the requesting entities in 14 or more calendar days but not more than 22 calendar days of determining CBM | The Transmission Service Provider provided the report to the requesting entities 22 or more calendar days after determining CBM or did not provide the report. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R7. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM in more than seven, but not more than fourteen, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM in more than fourteen, but not more than thirty, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM more than thirty, but not more than sixty, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM more than sixty days after the submission of the request. |
| R8. | N/A | N/A | N/A | A Load Serving Entity requested to schedule energy over CBM while not in an EEA2 |
| R9. | N/A | N/A | N/A | A Balancing Authority or Transmission Service Provider denied an Arranged Interchange using CBM based on timing or ramping requirements. |
| R10. | N/A | N/A | N/A | The Transmission Service Provider failed to approve an Arranged interchange for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available.” |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes the modifications with consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Generation Capability Import Requirement (GCIR):** The amount of generation capability from external sources requested by a Load-Serving Entity (LSE) (or group of LSEs with an aggregated need for Capacity Benefit Margin) to meet its generation reliability or resource~~serve~~ adequacy requirements as an alternative to internal resources.

**Capacity Benefit Margin Implementation Document (CBMID):** A document that describes the implementation of a Capacity Benefit Margin methodology.

**Planned Resource Sharing Group (PRSG):** A group of Load-Serving Entities who have agreed to jointly meet their resource adequacy requirements~~.~~.

## A. Introduction

1. **Title:** **Capacity Benefit Margin**

2. **Number:** **MOD-004-1**

3. **Purpose:** To promote the consistent and ~~transparent~~ reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support ~~reliable~~ analysis and system operations.

4. **Applicability:**

   **4.1. Functional Entity:**

   **4.1.1** Load-Serving Entity.

   **4.1.2** Planned Resource Sharing Group.

   **~~4.1.2~~4.1.3** Transmission Service Providers that maintain CBM.

   **~~4.1.3~~4.1.4** Balancing Authority.

   **~~4.1.4~~4.1.5** Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM.

5. **Facility Limitations/Specifications:**

   **5.1.** None.

6. **Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that ~~all six~~ this standard~~s~~ ~~are~~ is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard ~~Reliability Standards~~ become effective on the first day of the first calendar quarter that is twelve months beyond the date ~~the set of~~this standard~~s~~ ~~are~~ is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service Provider shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

**R1.1.** Its procedure for a Load-Serving Entity or Planned Resource Sharing Group within a Balancing Authority associated with the Transmission Service Provider to request ~~CBM to support its~~ the Generation Capability Import Requirement (GCIR) including the disposition and handling of deficient requests~~; and~~.

**R1.2.** Its procedure and assumptions for setting CBM for each ~~Posted~~ ATC Path or Flowgate based on Load-Serving Entity or ~~PRSG~~Planned Resource Sharing Group GCIR~~requests~~.

**R1.3.** Its procedure ~~for a Load-Serving Entity~~ to request the ~~scheduling of energy over utilizatio~~sen of Transfer Capability set aside as CBM.

**R1.4.** A statement of whether the Transmission Service Provider allows ATC or AFC to be less than zero due to CBM.

**R2.** The Transmission Service Provider shall make available ~~the~~ its CBMID and any changes to the CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area prior to the effective date ~~within seven days~~ of a change. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.** A Load-Serving Entity ~~(~~or ~~PRSG~~Planned Resource Sharing Group~~group of Load-Serving Entities with an aggregated need for CBM)~~ that wants Transfer Capability to be set aside in the form of CBM shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

**R3.1.** Submit an annual ~~request for CBM~~ GCIR request to the Transmission Service Provider and Transmission Planner per the specifications in the CBMID ~~identifying the amount of CBM requested for each month for each year for the next ten year period,~~ that includes:

**R3.1.1.** The GCIR, specifying:

~~3.1.1.1.The Balancing Authority(ies) from which generation supporting the GCIR will be supplied or the specific Posted Paths to be utilized for import of the generation supporting the GCIR.~~

~~3.1.1.2.~~3.1.1.1. A monthly GCIR value for each month for the next 24 months. If monthly values are not a requirement as per the applicable reserve margin and resource adequacy requirements documented in R3.1.2, a yearly GCIR value ~~will be sufficient~~ for the current ~~during the current year~~ and following year will be sufficient ~~for each Balancing Authority or Posted Path~~.

3.1.1.2. An annual GCIR value for each subsequent year for each Balancing Authority or Posted Path not to exceed 10 years into the future.

3.1.1.3. The location of the load ~~being~~ served by the GCIR (e.g., Balancing Authority, zones, markets ~~, etc~~…).

3.1.1.4. Assumed external resources (e.g., Balancing Authority(ies), specific generators, markets ~~, etc~~…) from which generation supporting each GCIR value of 3.1.1.1 and 3.1.1.2 will be supplied or the specific ATC Paths to be u~~tiliz~~sed for import of the generation supporting the GCIR.

**R3.1.2.** Identification of all applicable reserve margin and resource adequacy requirements, and the entity(ies) responsible for establishing them, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities.

3.1.2.1. The process and periodicity of calculating or recalculating GCIR if the entities specified in R3.1.2 require calculating GCIR on a frequency different than specified in R3.1.1

**R3.1.3.** A summary of the results of resource studies performed to determine the amount of the request, not to include confidential information.

**R3.1.4.** All resource studies (and supporting information) performed to determine the amount of the request.

**R3.2.** ~~At least e~~Every thirty-one calendar days, each Load Serving Entity or ~~PRSG~~Planned Resource Sharing Group shall ~~review its GCIR request and~~ adjust ~~that~~ its GCIR request, if necessary per 3.1.1 or 3.1.2.1, to reflect any incremental increase or decrease in required GCIR by either simple adjustment or through recalculation. ~~update the request provided per R3.1 to reflect any changes that alter future needs for CBM or indicate that no change is needed~~.

**R3.3.** Base the request provided per R3.1 on studies conducted in accordance with verifiable historical, state, regional transmission organization or regional entity criteria.

**R4.** Within fourteen calendar days of receiving a request or change to a ~~request for CBM~~ GCIR request that meets the requirements defined in R3.1, the Transmission Service Provider shall set the CBM for the next 13 months requested as described in R3.1~~.1.2~~ as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.1.** Determine the amount of CBM (for use in R4.2) for each request by using one of the following~~:~~:

**R4.1.1.** For the Area Interchange Methodology and the Rated System Path Methodology, using the requested Generation Capability Import Requirement for the appropriate ATC~~Posted~~ Path(s)

**R4.1.2.** For the Flowgate Methodology, determining the significant impacts of each request on each Flowgate

4.1.2.1. Determine impacts of a request by multiplying the requested GCIR by the Distribution Factor for the ~~transfer of that~~ import ~~from the specified Balancing Authority~~ relative to the Flowgate or model the GCIR explicitly in the AFC model per R3.1.1.3 and R3.1.1.4.

~~4.1.2.2.Classify each impacts based on a Distribution Factor of 3% or greater as a significant impact.~~

**R4.2.** For the Area Interchange Methodology and the Rated System Path Methodology, ~~S~~set CBM for each ~~Posted~~ ATC Path ~~or Flowgate based on~~ equal to the sum of all requests such that all requests can be met simultaneously or all firm ATC ~~or AFC~~ has been allocated to CBM as follows:

~~**R4.2.1.**For Posted Paths, set the CBM for each Posted Path equal to the lesser of:~~

**R4.2.1.** If the situation exists where there is insufficient capability on the ATC Path to satisfy ~~T~~the sum of all ~~requests for GCIR~~GCIR requests and the Transmission Service Provider, per R1.4, does not allow ATC to be less than zero, then the Transmission Service Provider ~~w~~sha~~i~~ll set the CBM such that the monthly ATCs equal~~s~~ zero

**R4.2.2.** If the situation exists where there is insufficient capability on the ATC Path to satisfy the sum of all ~~requests for GCIR~~GCIR requests and the Transmission Service Provider, per R1.4, allows the ATC to be less than zero, then the Transmission Service Provider- ~~wi~~shall set the CBM equal to the sum of the requested GCIR for that ATC Path.~~ for that Posted Path, minus the transfer capability set aside for reserve sharing for that Posted Path or~~

~~-The firm Available Transfer Capability (ATC) for that Posted Path~~

**R4.3.** For the Flowgate Methodology~~s,~~ set ~~the~~ CBM for each Flowgate equal to the sum of all requests on that Flowgate such that all requests can be met simultaneously o~~f~~r all firm ATC has been allocated to CBM as follows~~:lesser of~~:

**R4.3.1.** If the situation exists where there is insufficient Flowgate AFC to satisfy the sum of all ~~requests for GCIR~~GCIR requests and the Transmission Service Provider, per R1.4, does not allow the Flowgate AFC to be less than zero, then the Transmission Service Provider ~~wi~~shall set the CBM such that the monthly Flowgate AFCs equal~~s~~ zero

**R4.3.2.** If the situation exists where there is insufficient Flowgate AFC to satisfy the sum of all ~~requests for GCIR~~GCIR requests and the Transmission Service Provider, per R1.4, allows the Flowgate AFC to be less than zero, then the Transmission Service Provider shall set the CBM equal to the sum of the requested GCIR for that Flowgate.

~~-The sum of the significant impacts of all requests for GCIR for that Flowgate minus the impact of transfer capability set aside for reserve sharing for that Flowgate, or~~

~~-The firm Available Flowgate Capability (AFC) for that Flowgate~~

~~**R4.4.**If the sum of all CBM requests can not be met simultaneously, and during the evaluation of monthly ATC or AFC, additional capacity becomes available, increase the CBM based on availability up to a maximum of the sum of all CBM requests.~~

**R5.** Within sixty calendar days of receiving a request or change to a ~~request for CBM~~ GCIR request that meets the requirements defined in R3.1, the Transmission Planner shall: ~~set the CBM for the years requested as described in R3.1.1.3 as follows:~~ [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** As per R3.1.1.3 and R3.1.1.4, model the GCIR explicitly in the ATC/AFC model or use the CBM calculated using requirements R4.1 through R4.3 for all years requested beyond 13 months not to exceed 10 years

~~**R5.1.**Use each GCIR to determine a margin to decrement Firm Transfer Capability for use in all future planning processes.~~

~~**R5.2.**Set the CBM for each Posted Path or Flowgate based on the sum of all CBM requests such that all requests can be met simultaneously or all available firm Transfer Capability has been allocated to CBM.~~

~~**R5.3.**If the sum of all requests can not be met simultaneously, and during the planning process, additional capacity becomes available, increase the CBM based on availability up to a maximum of the sum of all requests.~~

**~~R5.4.~~R5.2.** If so requested, ~~P~~provide the Transmission Service Provider with the following:

**~~R5.4.1.~~R5.2.1.** The total amount of CBM for each ~~Posted~~ ATC Path or Flowgate on the Transmission Service Provider's system in each of the years specified in the original CBM request not to exceed 10 years.

**~~R5.4.2.~~R5.2.2.** If less than the sum of all requests was established as the CBM for any period, for each ~~Posted~~ ATC Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the years specified in the original request not to exceed 10 years.

**R6.** Within ~~five~~ seven calendar days of the determination of CBM as described in R4 or R5, the Transmission Service Provider shall provide each Load-Serving Entity ~~(or group of Load-Serving Entities with an aggregated need for CBM)~~ or ~~PRSG~~Planned Resource Sharing Group that requested CBM and the Balancing Authority hosting its (their) load with a report that includes: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** The total amount of CBM for each ~~Posted~~ ATC- Path or Flowgate on the Transmission Service Provider's system in each of the months or years specified in the original request.

**R6.2.** If less than the sum of all requests was established as the CBM for any period:

- For each ~~Posted~~ ATC Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the months and years specified in the original request
- The option to pursue alternatives, including expansion, with the Transmission Service Provider~~request a system impact study~~.

**R7.** The Transmission Service Provider and Transmission Planner shall each provide copies of the supporting data, including any models, used for allocating CBM over each ~~Posted~~ ATC Path or Flowgate to the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

**R7.1.** Each of its associated Transmission Operators within ~~seven~~ thirty calendar days of their making a request for the data~~a modification to the CBM~~.

**R7.2.** To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, or Planning Coordinator within ~~seven~~ thirty calendar days of their making a request for the data.

**R8.** The Load-Serving Entity or Balancing Authority that wants to schedule energy over ~~Firm~~ firm Transfer Capability set aside as CBM shall submit an Arranged Interchange

~~Transaction Tagto the Interchange Authority~~, and shall not request to schedule energy over ~~F~~firm Transfer Capability set aside as CBM unless experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [*Violation Risk Factor: Lower*] [*Time Horizon: Same-day Operations ~~Planning~~*]

**R9.** When reviewing an Arranged Interchange ~~Transaction Tag~~ using CBM, the Balancing Authority and Transmission Service Provider shall waive, within the bounds of reliable operation, any real-time timing and ramping requirements. [*Violation Risk Factor: Lower*] [*Time Horizon: Same-day Operations ~~Planning~~*]

**R10.** The Transmission Service Provider shall approve any Arranged Interchange ~~Transaction Tag~~ using CBM that is submitted by an Energy Deficient Entity[1] under an EEA2 if the CBM is available. [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations ~~Planning~~*]

[1] See Attachment 1-EOP-002-0 for definition.

## C. Measures

**M1.** Each Transmission Service Provider shall produce ~~have~~ its CBMID evidencing inclusion of all ~~specified that includes the~~ information specified in ~~specified in~~ R1 ~~as to show that it is compliant with R1~~. (R1)

**M2.** ~~The~~ Each Transmission Service Provider shall have evidence (such as dated logs and data, copies of dated electronic messages, or other equivalent evidence) to show that prior to the effective date ~~within seven days~~ of a change to its CBMID, it made the CBMID available to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators specified in R2. (R2)

**M3.** ~~The~~ Each Load-Serving Entity or ~~PRSG~~Planned Resource Sharing Group that wants CBM shall provide a copy of its ~~CBM~~ GCIR request with the supporting information specified in R3.1 to show that it is compliant with R3.1. (R3)

**M4.** ~~The~~ Each Load-Serving Entity or ~~PRSG~~Planned Resource Sharing Group that requests changes to its GCIR~~wants CBM~~ as per R3.2 shall provide dated copies of its updated ~~CBM~~ GCIR along with studies or documentation of the changes ~~which~~that support ~~their~~its request; such as Transmission Service Requests, generator outage reports, and load-forecast changes ~~which~~that affect ~~their~~ its resource adequacy requirements documented in R3.1.2. ~~requests as evidence that it has updated its CBM request or confirmed no update was needed at least every thirty-one days, per R3.2~~ (R3).

**M5.** ~~The~~ Each Load-Serving Entity or ~~, PRSG~~Planned Resource Sharing Group that wants CBM shall provide evidence (such as studies, historical data, copies of state or regional transmission organization reliability criteria, regional generation reliability criteria or other equivalent evidence) that ~~they~~ it has based its ~~CBM~~GCIR request on verifiable historical, state, regional transmission organization, or regional generation reliability criteria in accordance with R3.3. (R3)

**M6.** ~~The~~ Each Transmission Service Provider shall provide evidence including copies of ~~requests for CBM~~ GCIR requests and requests for GCIR changes ~~to CBM GCIR~~ and other evidence such as copies of the actual computations to set CBM, or other equivalent evidence to show that CBM for the months requested as described in R3.1.1~~.2~~ has been established using the process described in R4. (R4)

**M7.** ~~The~~ Each Transmission Planner shall provide ~~evidence~~ evidence ~~(such as written documentation of studies and supporting study models that model base loadflow)~~ including copies of ~~requests for CBM~~ GCIR requests and requests for GCIR changes ~~to CBM GCIR~~ and other evidence (such as written documentation of studies and supporting study models that model base load flow, ~~such as~~ copies of actual computations to set CBM, or other equivalent evidence)~~-~~ to show that the GCIR has been used to either model GCIR or calculate as per the process ~~CBM for the years requested as described in R3.1.1.3 has been established using the process~~ described in R5. (R5)

~~**M8.**The Transmission Planner shall provide evidence (such as written documentation of studies and supporting study models that model, in base loadflows, the GCIRs as~~

~~identified in R3.1.1 by Load-Serving Entities) that demonstrates that the CBM has been used to determine a margin to decrement Firm Transfer Capability in planning processes as specified in R5.1. (R5)~~

**~~M9.~~M8.** ~~The~~Each Transmission Service Provider shall provide copies of the reports sent to Load-Serving Entities and Balancing Authorities along with other evidence (such as logs and data, copies of electronic messages, or other equivalent evidence) to show that within ~~five~~ seven calendar days of the determination of CBM, a report meeting the requirements described in R6 was provided as specified. (R6).

**~~M10.~~M9.** ~~The~~ Each Transmission Service Provider and Transmission Planner shall each provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show- that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in R7. (R7)

**~~M11.~~M10.** ~~The~~ Each Load-Serving Entity that scheduled energy over firm Transfer Capability set aside as CBM shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time they requested ~~a~~ the schedule using CBM, they were in an EEA2. (R8)

**~~M12.~~M11.** Each Balancing ~~Authorities~~ Authority and Transmission Service Provider~~s~~ shall provide evidence (such as operating logs and tag data) that it waived real-time timing and ramping requirements when approving an ~~they did not deny an Interchange Schedule~~Arranged Interchange using CBM ~~based on the request not meeting timing or ramping requirements.~~ (R9)

**~~M13.~~M12.** ~~The~~ Each Transmission Service Provider shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any ~~Interchange Transaction Tag~~Arranged Interchange using CBM for any ~~energy~~ Energy ~~deficient~~ Deficient ~~entity~~ Entity[2] where the total CBM available was greater than the amount of CBM requested in the ~~Tag~~Arranged Interchange. (R10)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority (CEA)

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

[2] See Attachment 1-EOP-002-0 for definition.

- The Transmission Service Provider shall maintain its current, in force ~~ATCID~~ CBMID and any prior versions of the ~~ATCID~~ CBMID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7 and R10 for the most recent three calendar years plus the current year.
- The Load-Serving Entity ~~or~~and ~~PRSG~~Planned Resource Sharing Group shall each maintain evidence to show compliance with R3, and R8 for the most recent three calendar years plus the current year.
- The Transmission Planner shall maintain evidence to show compliance with R5 and R7 for three calendar years.
- The Balancing Authority shall maintain evidence to show compliance with R9 for three calendar years.
- If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

**None.**

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made within the last three months. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago.<br>**OR**<br>The Transmission Service Provider's CBMID does not address one of the sub requirements. | The Transmission Service Provider has CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago.<br>**OR**<br>The Transmission Service Provider's CBMID does not address two of the sub requirements. | The Transmission Service Provider ~~does not have a CBMID, or~~ has a CBMID that does not incorporate changes that have been made more than twelve months ago.<br>**OR**<br>The Transmission Service Provider does not have a CBMID;<br>**OR**<br>The Transmission Service Provider's CBMID does not address three or more of the sub requirements. |
| R2. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator ~~eight (8)~~14 or more calendar days but not more than ~~14~~ 30 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator ~~14~~ 30 or more calendar days but not more than ~~21~~ 60 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator ~~21~~ 60 or more calendar days but not more than ~~28~~ 90 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator more than ~~28~~ 90 calendar days after a change was made. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Load Serving Entity or Planned Reserve Sharing Group did not update ~~their~~ its request for CBM, or indicate that no update was needed, as described in R3.2. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit the information ~~described in~~ required by any one of the following: R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update ~~their~~ its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 20MW or 10%, whichever is smaller, and not more than 30MW or 20%, whichever is smaller. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit the information ~~described in any one~~two or more of the following: R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update ~~their~~ its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 3~~2~~0MW or 2~~1~~0%, whichever is smaller, and not more than 40MW or 30%, whichever is smaller. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not include one or more of the items specified in R3.1.1 in ~~their~~ its request.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit any of the information described in R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update ~~their~~ its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 40MW or 30%, whichever is smaller.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group requested GCIR greater than its needs for imports to meet reserve margin or resource adequacy requirements (not to include the incremental power flows from reserve sharing requirements), and the additional GCIR |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | requested was more than 10MW in excess of the needed amount. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | N/A | N/A | The Transmission Service Provider set CBM for the months requested as described in R~~3.1.1.2~~ 4 more than 14, but not more than 30~~,~~ calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Service Provider did not follow the process described in R4~~.1, R4.2, and R4.3~~. | The Transmission Service Provider set CBM for the months requested as described in R~~3.1.1.2~~ 4 more than 30 calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Service Provider did not follow the process described in R4~~.1, R4.2, and R4.3,~~ and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met. |
| R5. | N/A | N/A | The Transmission Planner set CBM for the years requested as described in R~~3.1.1.3~~ 5 more than 60, but not more than 120, calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Planner did not follow the process described in R5~~.1, R5.2, R5.3, and R5.4~~. | The Transmission Planner set CBM for the years requested as described in R~~3.1.1.3~~ 5 more than 120 calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Planner did not follow the process described in R5~~.1, R5.2, R5.3, and R5.4~~, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met. |
| R6. | The Transmission Service Provider provided the report to the requesting entities in more than ~~5~~7 calendars days but not more than ~~within 7~~9 calendar days ~~(up to 2 days late)~~ of | The Transmission Service Provider provided the report to the requesting entities in ~~7~~9 or more calendar days but not more than ~~within~~ 1~~2~~4 calendar days ~~(up to 7 days late)~~ of | The Transmission Service Provider provided the report to the requesting entities in 1~~2~~4 or more calendar days but not more than 2~~0~~2 calendar days ~~within 19 days (up to 14 days~~ | The Transmission Service Provider provided the report to the requesting entities ~~within 20~~ 22 or more calendar days ~~of~~ after determining CBM or did not provide the report. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | determining the CBM | determining CBM | ~~late)~~ of determining CBM | |
| R7. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM in more than seven, but not more than fourteen, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM in more than fourteen, but not more than thirty, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM more than thirty, but not more than sixty, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM more than sixty days after the submission of the request. |
| R8. | N/A | N/A | N/A | A Load Serving Entity requested to schedule energy over CBM while not in an EEA2 |
| R9. | N/A | N/A | N/A | A Balancing Authority or Transmission Service Provider denied an ~~Interchange Transaction Tag~~Arranged Interchange using CBM based on timing or ramping requirements. |
| R10. | N/A | N/A | N/A | The Transmission Service Provider failed to approve an Arranged interchange for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available.”~~The responsible entity has failed to demonstrate implementation or execution of the program/procedure requirement~~ |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | ~~or directive~~ |

NERC
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# Implementation Plan for Standard MOD-004-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-004-1, which describes the reliability aspects of determining and maintaining a Capacity Benefit Margin and the conditions under which that margin may be used.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes MOD-004-0. MOD-005-0, MOD-006-0, and MOD-007-0 have been incorporated into this standard, made irrelevant by this standard, or are being addressed by the North American Energy Standards Board, and should be retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-004-1 | | ■ | ■ | ■ | | ■ |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC Authorized posting TTC/ATC/AFC SAR Development June 20 2005.
2. SAC Authorized the SAR to be development as a standard on February 14 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from February 15–March 16, 2007.
5. SDT posted second draft for comment from May 25–June 25, 2007.
6. SDT posted third draft for comment from October 31–December 15, 2007.

**Description of Current Draft:**

This is the fourth and final draft of the proposed standard posted for stakeholder comments. This draft represents consideration of stakeholder comments submitted with the third draft of the proposed revisions to MOD-001 as well as consideration of applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**ATC Path:** Any combination of Point of Receipt and Point of Delivery for which ATC is calculated.

**Available Transfer Capability Implementation Document (ATCID):** A document that describes the implementation of an Available Transfer Capability methodology.

**Transmission Operator Area:** The collection of Transmission assets over which the Transmission Operator is responsible for operating.

**Existing Transmission Commitments (ETC):** Committed uses of a Transmission Service Provider's Transmission system considered when determining Available Transfer Capability.

**Planning Coordinator:** See Planning Authority.

**Postback:** Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

**Business Practices:** Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization business practices; or NAESB Business Practices**.**

**Block Dispatch:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

**Dispatch Order:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

**Participation Factors:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

## A. Introduction

1. **Title:** **Available Transfer Capability**

2. **Number:** **MOD-001-1**

3. **Purpose:** To promote the consistent and reliable application and documentation of Available Transfer Capability (ATC) calculations for analysis and system operations.

4. **Applicability:**

   **4.1.** Transmission Service Provider.

   **4.2.** Transmission Operator.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall select one ATC methodology[1] (Area Interchange methodology, Rated System Path methodology, or Flowgate methodology) for each ATC Path per time period identified in R2 for use in determining Transfer Capabilities of those Facilities within its Transmission operating area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R2.** Each Transmission Service Provider shall calculate ATC values as listed below using the ATC methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Hourly ATC values for at least the next 168 hours.

**R2.2.** Daily ATC values for at least the next 31 calendar days.

**R2.3.** Monthly ATC values for at least the next 12 months (months 2-13).

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC calculations can be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows including:

[1] All ATC Paths do not have to use the same ATC Methodology and no particular ATC Path must use the same ATC Methodology for all time periods.

**R3.2.1.** How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC calculations.

**R3.2.2.** A rationale for the defined accounting.

**R3.3.** The identity of the Transmission Operators from which the Transmission Service Provider receives data for use in calculating ATC.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer capability.

**R3.5.** The identity of the Transmission Service Providers from which it receives data for use in calculating transfer capability.

**R3.6.** A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate Transfer Capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate Transfer Capabilities among multiple owners or users of a single path or Flowgate.
- Processes used to allocate AFC between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

**R3.7.** A description of how outage durations are considered in ATC calculations, including:

**R3.7.1.** The criteria used to determine when an outage impacts a daily ATC calculation.

**R3.7.2.** The criteria used to determine when an outage impacts a monthly ATC calculation.

**R4.** The Transmission Service Provider shall notify the following entities (via electronic mail) before implementing a new or revised ATCID: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

**R4.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

**R4.3.** Each Transmission Operator associated with the Transmission Service Provider's area.

**R4.4.** Each Planning Coordinator adjacent to the Transmission Service Provider's area.

**R4.5.** Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

**R4.6.** Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

**R5.** The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.** When calculating TTC, AFC and ATC, the Transmission Operator and Transmission Service Provider shall each use assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.** Each Transmission Service Provider shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.1.** For hourly ATC, once per hour.

**R7.2.** For daily ATC, once per day.

**R7.3.** For monthly ATC, once a week.

**R8.** Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below for use in ATC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R8.1 and R8.2: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Confirmed firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.

- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), and TTC for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

**R8.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

**R8.2.** This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one or more of the specified ATC methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator's operating area. (R1).

**M2.** The Transmission Service Provider shall provide ATC values and identification of the selected ATC methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 168 hours of hourly ATC values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily ATC values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly ATC values calculated at all times (Months 2–13). (R2.3)

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** The Transmission Service Provider shall provide evidence (such as dated electronic mail messages) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

**M5.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

**M6.** The Transmission Service Provider and Transmission Operator shall each provide a copy of the assumptions (such as loop flow, generation re-dispatch, switching operating guides, load shedding or data sources for load forecast and facility outages) used to calculate TTC, ATC and AFC as well as other evidence (such as copies of operations and planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC, ATC, and AFC were consistent with those used in operations or planning studies for the time period studied. (R6)

**M7.** The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly ATC on at least the minimum frequencies specified in R7 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R7)

**M8.** The Transmission Service Provider shall provide a copy of the dated request for ATC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R8. (R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.

- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Operator did not select one or more of the specified methodologies. |
| R2. | N/A | N/A | N/A | The Transmission Service Provider did not calculate ATCs based on the time periods in R2.<br>**OR**<br>Did not use the selected methodology(ies) to calculate ATC. |
| R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>**OR**<br>The Transmission Service Provider has an ATCID, but it does not include two or more of the information items described in R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>**OR**<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include any of the information described in R3. |
| R4. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 14, but not more than 30, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation. | The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in R5 |
| R6. | N/A | N/A | N/A | The Transmission Service Provider or Transmission Operator did not determine ATC using assumptions consistent with those used in planning or operations studies for the studied time period. |
| R7. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 12 hours but not more than 15 hours,<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 2 calendar days but not more than 3 calendar days,<br>**OR**<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 8 or more calendar days, but less than 14 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours,<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days,<br>**OR**<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours,<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days,<br>**OR**<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours,<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days,<br>**OR**<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R8 | N/A | The Transmission Service Provider made the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available more than 30 calendar days but less than 45 calendar days after receiving a request. | The Transmission Service Provider made the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available 45 calendar days or more but less than 60 calendar days after receiving a request. | The Transmission Service Provider did not make the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available for 60 calendar days or more after receiving a request. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC Authorized posting TTC/ATC/AFC SAR Development June 20 2005.
2. SAC Authorized the SAR to be development as a standard on February 14 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from February 15–March 16, 2007.
5. SDT posted second draft for comment from May 25–June 25, 2007.
6. SDT posted third draft for comment from October 31–December 15, 2007.

**Description of Current Draft:**

This is the fourth and final draft of the proposed standard posted for stakeholder comments. This draft represents consideration of stakeholder comments submitted with the third draft of the proposed revisions to MOD-001 as well as consideration of applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

~~**Posted Path:**~~

~~1)Any Balancing Authority to Balancing Authority interconnection;~~

~~2)Any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months;~~

~~3)Any path for which a Transmission Customer requests to have Available Transfer Capability or Total Transfer Capability posted.~~

**ATC Path:** Any combination of Point of Receipt and Point of Delivery for which ATC is calculated.

**Available Transfer Capability Implementation Document (ATCID):** A document that describes the implementation of an Available Transfer Capability methodology.

**Transmission Operator Area:** The collection of Transmission assets over which the Transmission Operator is responsible for operating.

**Existing Transmission Commitments (ETC):** Committed uses of a Transmission Service Provider's Transmission system considered when determining Available Transfer Capability.

**Planning Coordinator:** See Planning Authority.

**Postback:** Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

**Business Practices:** Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization business practices; or NAESB Business Practices.

**Block Dispatch:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

**Dispatch Order:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

**Participation Factors:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

## A. Introduction

1. **Title:** **Available Transfer Capability**

2. **Number:** **MOD-001-1**

3. **Purpose:** To promote the consistent and ~~transparent~~ reliable application and documentation of Available Transfer Capability (ATC) calculations for ~~reliable~~ analysis and system operations.

4. **Applicability:**

   **4.1.** Transmission Service Provider.

   **4.2.** Transmission Operator.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that ~~all six (~~MOD-001-1, ~~MOD-004-1, MOD-008-1,~~ MOD-028-1, MOD-029-1, and ~~-~~MOD-030-1~~)ATC-related standards~~ are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall select one ATC methodology[1] (Area Interchange methodology, Rated System Path methodology, or Flowgate methodology) for each ~~Posted~~ ATC Path per time period identified in R2 for use in determining Transfer Capabilities of those Facilities within its Transmission ~~Planning Coordinator's planning~~operating area. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.** Each Transmission Service Provider shall calculate ATC values ~~for the time periods~~as listed below using the ~~selected~~ ATC methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Hourly ATC values for at least the next 168 hours.

**R2.2.** Daily ATC values for at least the next 31 calendar days.

**R2.3.** Monthly ATC values for at least ~~the current month plus~~ the next 12 months (months 2-13).

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC calculations ~~may~~ can be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows ~~or counter-schedules~~including:

**R3.2.1.** How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC calculations.

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[1] All ~~Posted~~ ATC Paths do not have to use the same ATC Methodology and no particular ~~Posted~~ ATC Path must use the same ATC Methodology for all time periods.

**R3.2.2.** A rationale for the defined accounting.

**R3.3.** The identity of the ~~Planning Coordinator and~~ Transmission Operators ~~associated with each Facility under the Transmission Service Provider's tariff~~from which the Transmission Service Provider receives data for use in calculating ATC.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer capability.

**R3.5.** The identity of the Transmission Service Providers from which it receives data for use in calculating transfer capability.

**R3.6.** A description of the a~~A~~llocation ~~methodologies~~processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate Transfer Capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate Transfer Capabilities among multiple owners or users of a single path or Flowgate.
- Processes used to allocate AFC between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

**R3.7.** A description of how outage durations are considered in ATC calculations, including:

**R3.7.1.** The criteria used to determine when an outage impacts a daily ATC calculation.

**R3.7.2.** The criteria used to determine when an outage impacts a monthly ATC calculation.

~~**R4.** When determining the impact of counterflows in the determination of firm ATC or AFC, the Transmission Service Provider shall use 0% of calculated counterflows based on reservations and/or schedules unless otherwise specified within the Transmission Service Provider's ATCID. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]~~

~~**R5.** When determining the impact of counterflows in the determination of non-firm ATC or Available Flowgate Capability (AFC), the Transmission Service Provider shall apply the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]~~

~~**R5.1.** Use 0% of calculated counterflows based on reservations unless otherwise specified within the Transmission Service Provider's ATCID.~~

~~**R5.2.** Use 100% of calculated counterflows based on schedules unless otherwise specified within the Transmission Service Provider's ATCID.~~

~~**R6.**~~**R4.** The Transmission Service Provider shall notify the following entities (via electronic mail) before implementing a new or revised ATCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

~~**R6.1.**~~**R4.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

~~**R6.2.**~~**R4.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

~~R6.3.~~R4.3. Each Transmission Operator associated with the Transmission Service Provider's area.

~~R6.4.~~R4.4. Each Planning Coordinator adjacent to the Transmission Service Provider's area.

~~R6.5.~~R4.5. Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

~~R6.6.~~R4.6. Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

~~R7.~~R5. The Transmission Service Provider shall make available the current ATCID ~~and any changes to the ATCID~~ to all of the entities specified in ~~R6~~R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~R8.~~R6. When calculating ~~Total Transfer Capability (~~TTC~~)~~, AFC and ATC, the Transmission Operator and Transmission Service Provider shall each use assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~R9.~~R7. Each Transmission Service Provider shall ~~update~~ recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

~~R9.1.~~R7.1. For hourly ATC, once per hour.

~~R9.2.~~R7.2. For daily ATC, once per day.

~~R9.3.~~R7.3. For monthly ATC, once a week.

~~R10.~~R8. Within ~~fourteen~~ thirty calendar days of receiving a request ~~of~~ by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below for use in ATC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R8.1 and R8.2:~~available on the schedule specified by the requester (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider), unless another request already specifies data on a more frequent basis, to each requester, current versions of the following data as requested in electronic format for use in ATC calculations, for up to 13 months into the future (subject to confidentiality and security requirements):~~ *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- ~~P10.1.~~ Expected generation and Transmission outages, additions, and retirements.
- ~~P10.2.~~ ~~Peak~~ Load forecasts.
- ~~P10.3.~~ Unit commitments and ~~dispatch~~ order~~s~~ of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch O~~o~~rder
  - Participation F~~f~~actors
  - Block D~~d~~ispatch

- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (~~i.e~~i.e. Secondary Service).
- ~~Firm and non-firm Network Integration Transmission Service details.~~

~~P10.5.~~• Confirmed firm and non-firm Transmission reservations.

- Aggregated capacity set-aside for Grandfathered obligations
- ~~Grandfathered firm and non-firm contracted transmission capacity on an aggregated basis.~~

~~P10.7.~~• Firm roll-over rights.

~~P10.8.~~• Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.

~~P10.9.~~• Power flow models and underlying assumptions.

~~P10.10.~~• Contingencies, provided in one or more of the following formats:

- ~~–~~ A list of Elements
- ~~–~~ A list of Flowgates
- ~~–~~ A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider

~~P10.11.~~• Facility Ratings.

- Any other services that impact Existing Transmission Commitments (ETCs).

~~•Counterflows.~~

~~P10.13.~~• Values of ~~ATC, ETC,~~ Capacity Benefit Margin (CBM~~),~~) and Transmission Reliability Margin (TRM), and TTC for all ~~Posted~~ ATC Paths or Flowgates.

~~P10.14.~~• Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.

- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.

~~P10.15.~~• Source and sink identification and mapping to the model.

**R8.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, -for up to 13 months into the future (subject to confidentiality and security requirements).

**R8.2.** This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one or more of the specified ATC methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ~~Posted~~ ATC Path within the ~~Planning Coordinator's planning~~Transmission Operator's operating area. (R1).

**M2.** The Transmission Service Provider shall provide ATC values and identification of the selected ATC methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC for the following using the selected methodology or methodologies chosen as part of R1 (R2~~1~~):

- There has been at least 168 hours of hourly ATC values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily ATC values calculated at all times. (R2.2)
- There has been at least the next 12 months ~~plus the current month~~ of monthly ATC values calculated at all times (Months 2-13). (R2.3)

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** ~~The Transmission Service Provider shall provide its ATCID and other evidence (such as documentation and data) to show that it determined counterflows based on the rules in R4 and R5. (R4) (R5)~~

~~**M5.**~~ The Transmission Service Provider shall provide evidence (such as ~~copies of its~~ dated electronic mail messages) ~~used to make notifications in accordance with R6 as evidence~~ that it has notified the entities specified in ~~R5~~ R4 before a new or revised ATCID was implemented. (~~R6~~R4)

**~~M6~~M5.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in ~~R6~~R4, as required by ~~R7~~R5. (~~R7~~R5)

**~~M7~~M6.** The Transmission Service Provider and Transmission Operator shall each provide a copy of the assumptions (such as loop flow, generation re-dispatch, switching operating guides, load shedding or data sources for load forecast and facility outages) used to calculate TTC, ATC and AFC as well as ~~copies of operations and planning studies and~~ other evidence (such as copies of operations and planning studies, ~~written documentation,~~ models, ~~studies,~~ supporting information, or data) to show that the assumptions used in determining TTC, ATC, and AFC were consistent with those used in operations or planning studies for the time period studied. (~~R8~~R6)

**~~M8~~M7.** The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has ~~updated~~ calculated the hourly, daily, and monthly ATC on at least the minimum frequencies specified in ~~R9~~R7 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R7)

**~~M9~~M8.** The Transmission Service Provider shall provide a copy of the dated request for ATC data as well as evidence to show ~~the its~~it ~~response~~ responded to that request (such as logs or data~~,~~) ~~to show that~~ within ~~fourteen~~ thirty calendar days of receiving ~~a~~ the request, and the requested data items ~~specified in R10~~ were made available in accordance with R~~10~~8. (R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

**1.3. Data Retention**

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, ~~R4, R5 and R8~~ R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- ~~The Transmission Service Provider shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.~~
- The Transmission Service Provider shall maintain evidence to show compliance with ~~R7~~ R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with ~~R8~~ R6 for the most recent calendar year plus the current year.
- ~~The Transmission Service Provider shall maintain evidence to show compliance with R9 and R10 for the most recent calendar year plus the current year.~~
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Operator did not select one or more of the specified methodologies. |
| R2. | N/A | N/A | N/A | The ~~Transmission Operator or~~ Transmission Service Provider did not calculate ATCs based on the time periods in R2.<br>**OR**<br>D~~d~~id not use the selected methodology(ies) to calculate ATC. |
| R3.<br>~~R4.~~<br>~~R5.~~ | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago.<br>~~N/A~~<br>~~N/A~~ | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago.<br>~~N/A~~<br>~~N/A~~ | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>**OR**<br>The Transmission Service Provider has an ATCID, but it does not include two or more of the information items described in R3.<br>~~N/A~~<br>~~N/A~~ | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>**OR**<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include any of the information described in R3.<br>~~The Transmission Service provider did not use counterflows in the determination of ATC as described in R4 or its ATCID.~~<br>~~The Transmission Service provider did not use counterflows in the determination of ATC as~~ |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | ~~described in R5 or its ATCID.~~ |
| ~~R6~~R4. | The Transmission Service Provider ~~did not notifyed~~notified one or more of the parties specified in ~~R6~~ R4 of a new or modified ATCID ~~within~~ more than 14, but not more than 30, calendar days ~~days~~ after~~of~~ its ~~effectiveness~~implementation. | The Transmission Service Provider ~~did not~~ notif~~y~~ied one or more of the parties specified in R~~6~~4 of a new or modified ATCID ~~within~~ more than 30, but not more than 60, calendar days after ~~of~~ its ~~effectiveness~~implementation. | The Transmission Service Provider ~~did not~~ notifie~~d~~y one or more of the parties specified in R4~~6~~ of a new or modified ATCID ~~within 60~~ more than 60, but not more than 90, calendar days ~~of~~ after its ~~effectiveness~~implementation. | The Transmission Service Provider did not notify one or more of the parties specified in R~~6~~4 of a new or modified ATCID ~~within 90~~for more than 90 calendar days ~~of~~ after its ~~effectiveness~~implementation. |
| ~~R7~~R5. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in ~~R7~~R5 |
| ~~R8~~R6. | N/A | N/A | N/A | The Transmission Service Provider or Transmission Operator did not determine ATC using assumptions consistent with those used in planning ~~and~~ or operations studies for the studied time period. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R9~~R7. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculat~~ed~~e ~~within~~ for more than 12 hours but not more than 15 hours,<br><br>**OR**<br><br>F~~f~~or Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculat~~ed~~e ~~in~~for more than ~~2 days~~2 calendar days but not more than 3 calendar days,<br><br>**OR**<br><br>F~~f~~or Monthly, the values described in the ATC equation changed and the Transmission Service provider did ~~-~~not ~~calculat~~calculate for~~ed in~~ 8 or more calendar days, but less than 14 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours,<br><br>~~For Hourly, not calculated in more than 5 hours but not more than 10 hours,~~<br><br>**OR**<br><br>F~~f~~or Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days,<br><br>~~for Daily not calculated in 3 days,~~<br><br>**OR**<br><br>~~f~~For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. ~~for Monthly- not calculated in 14 or more days, but less than 21 days~~ | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours,<br><br>~~For Hourly, not calculated in10 hours or more, but not more than 15 hours,~~<br><br>**OR**<br><br>F~~f~~or Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days,<br><br>~~for Daily not calculated in 4 days,~~<br><br>**OR**<br><br>~~f~~For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. ~~for Monthly- not calculated in 21 or more days, but less than 28 days~~ | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours,<br><br>~~For Hourly, not calculated in15 hours or more,~~<br><br>**OR**<br><br>F~~f~~or Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days,<br><br>~~for Daily not calculated in 5 days or more,~~<br><br>**OR**<br><br>F~~f~~or Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days. ~~for Monthly- not calculated in 28 or more days.~~ |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R10~~R8 | N/A | The Transmission Service Provider ~~took~~ made the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available more than ~~more than 14~~30 calendar days but ~~less~~ less than ~~than 28~~ 45 calendar days ~~from~~ after receiving a request~~, to make available the requested data items specified in R10 to the entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R10~~. | The Transmission Service Provider made the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available 45 calendar days or more but less than 60 calendar days after receiving a request~~,~~ .~~The Transmission Service Provider took 28 or more calendar days, but less than 60 calendar days from receiving a request, to make available the requested data items specified in R10 to the entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R10.~~ | The Transmission Service Provider did not make the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available for 60 calendar days or more after receiving a request~~,~~ .~~The Transmission Service Provider took 60 calendar days or more from receiving a request, to make available the requested data items specified in R10 to the entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R10.~~ |

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Implementation Plan for Standard MOD-001-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-001-1, which requires the selection of an ATC methodology and describes the parts of the ATC process that apply to all entities, regardless of methodology chosen.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes the current MOD-001-1.

This standard incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-001-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by the NERC Board of Trustees.  This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

**Maureen E. Long**
Standards Process Manager

February 1, 2008

**Re: Pre-ballot Windows and Ballot Pools Open**

**The Standards Committee announces the following standards action:**

**Six Pre-ballot Windows and Ballot Pools for Project 2006-07 — ATC/TTC and CBM/TRM Open February 1, 2008**

The standards listed below, related to the determination of Available Transfer Capability (ATC), Total Transfer Capability (TTC), Capacity Benefit Margin (CBM), and Transmission Reliability Margin (TRM), and an associated implementation plan, have all been posted for a 30-day pre-ballot review.

This set of standards is aimed at ensuring the consistent and transparent calculation, verification, and use of CBM, TRM, TTC, AFC, and ATC. The standards have been revised based on stakeholder comments, coordination with NAESB, and the directives in the FERC Orders 693 and 890. NERC has a commitment to deliver these standards to FERC by May 9, 2008.

- MOD-001 — Available Transfer Capability — An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data.

- MOD-004 — Capacity Benefit Margin — A standard that describes the requesting, calculation, and use of CBM.

- MOD-008 — Transmission Reliability Margin — A standard that describes the calculation and use of TRM.

- MOD-028 — Area Interchange Methodology — A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.

- MOD-029 — Rated System Path Methodology — A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.

- MOD-030 — Flowgate Methodology — A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

Each standard has its own ballot pool and its own list server as shown in the following table.

| ATC Ballot Pools | Ballot Pool List Server |
|---|---|
| ATC-TTC-CBM-MOD-001 | bp-MOD-001_in@nerc.com |
| ATC-TTC-CBM-MOD-004 | bp-MOD-004_in@nerc.com |
| ATC-TTC-CBM-MOD-008 | bp-MOD-008_in@nerc.com |
| ATC-TTC-CBM-MOD-028 | bp-MOD-028_in@nerc.com |
| ATC-TTC-CBM-MOD-029 | bp-MOD-029_in@nerc.com |
| ATC-TTC-CBM-MOD-030 | bp-MOD-030_in@nerc.com |

During the 30-day, pre-ballot window, members of a ballot pool may communicate with one another by using their "ballot pool list server[1]." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) Any member of the Registered Ballot Body may join as many of these ballot pools as desired — a member wanting to ballot all of the ATC-related standards must join all six of the ballot pools. The ballot pools will remain open up until **8 a.m. (EST) Monday, March 3, 2008**.

### Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

[1] For assistance in using a list server, contact Barbara Bogenrief at 609-452-8060.

*List of Standards Associated with Each VSL Ballot:*

**Balancing Resources and Demand (BAL)**

BAL-001-0 — Real Power Balancing Control Performance
BAL-002-0 — Disturbance Control Performance
BAL-003-0 — Frequency Response and Bias
BAL-004-0 — Time Error Correction
BAL-005-0 — Automatic Generation Control
BAL-006-1 — Inadvertent Interchange

**Critical Infrastructure, Communications, Voltage and Reactive (CIP/COM/VAR)**

CIP-001-1 — Sabotage Reporting
COM-001-1 — Telecommunications
COM-002-2 — Communications and Coordination
VAR-001-1 — Voltage and Reactive Control
VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules

**Emergency Operations (EOP)**

EOP-001-0 — Emergency Operations Planning
EOP-002-2 — Capacity and Energy Emergencies
EOP-003-1 — Load Shedding Plans
EOP-004-1 — Disturbance Reporting
EOP-005-1 — System Restoration Plans
EOP-006-1 — Reliability Coordination - System Restoration
EOP-008-0 — Plans for Loss of Control Center Functionality
EOP-009-0 — Documentation of Blackstart Generating Unit Test Results

**Facilities and Modeling (FAC/MOD)**

FAC-001-0 — Facility Connection Requirements
FAC-002-0 — Coordination of Plans for New Facilities
FAC-003-1 — Vegetation Management Program
FAC-008-1 — Facility Ratings Methodology
FAC-009-1 — Establish and Communicate Facility Ratings
FAC-013-1 — Establish and Communicate Transfer Capabilities
MOD-006-0 — Procedures for Use of CBM Values
MOD-007-0 — Documentation of the Use of CBM
MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation
MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
MOD-016-1 — Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management
MOD-017-0 — Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0 — Reports of Actual and Forecast Demand Data
MOD-019-0 — Forecasts of Interruptible Demands and DCLM Data
MOD-020-0 — Providing Interruptible Demands and DCLM Data
MOD-021-0 — Accounting Methodology for Effects of Controllable DSM in Forecasts

**Interchange, Personnel and Nuclear (INT/PER/NUC)**

INT-001-2 — Interchange Information
INT-003-2 — Interchange Transaction Implementation
INT-004-1 — Dynamic Interchange Transaction Modifications
INT-005-1 — Interchange Authority Distributes Arranged Interchange
INT-006-1 — Interchange Confirmation

INT-008-1 — Implementation of Interchange
INT-010-1 — Interchange Coordination Exemptions
PER-001-0 — Operating Personnel Responsibility and Authority
PER-002-0 — Operating Personnel Training
PER-003-0 — Operating Personnel Credentials
PER-004-1 — Reliability Coordination — Staffing
NUC-001-1 — Nuclear Plant Interface Coordination

**Interconnected Reliability Operations (IRO)**

IRO-001-1 — Reliability Coordination — Responsibilities and Authorities
IRO-002-1 — Reliability Coordination — Facilities
IRO-003-2 — Reliability Coordination — Wide-Area View
IRO-004-1 — Reliability Coordination — Operations Planning
IRO-005-1 — Reliability Coordination — Current-Day Operations
IRO-006-3 — Reliability Coordination — Transmission Loading Relief
IRO-014-1 — Procedures, Processes, Plans to Support Coordination Between Reliability Coordinators
IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators

**Protection and Control (PRC)**

PRC-001-1 — System Protection Coordination
PRC-004-1 — Analysis and Mitigation of Trans and Generation Protection Sys Misoperations
PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing
PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements
PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs
PRC-009-0 — UFLS Performance Following an Underfrequency Event
PRC-010-0 — Assessment of the Design and Effectiveness of UVLS Program
PRC-011-0 — UVLS System Maintenance and Testing
PRC-015-0 — Special Protection System Data and Documentation
PRC-016-0 — Special Protection System Misoperations
PRC-017-0 — Special Protection System Maintenance and Testing
PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting
PRC-021-1 — Under-Voltage Load Shedding Program Data
PRC-022-1 — Under-Voltage Load Shedding Program Performance

**Transmission Operations (TOP)**

TOP-001-1 — Reliability Responsibilities and Authorities
TOP-002-2 — Normal Operations Planning
TOP-003-0 — Planned Outage Coordination
TOP-004-1 — Transmission Operations
TOP-005-1 — Operational Reliability Information
TOP-006-1 —Monitoring System Conditions
TOP-007-0 — Reporting SOL and IROL Violations
TOP-008-1 — Response to Transmission Limit Violations

**Transmission Planning (TPL)**

TPL-001-0 — System Performance Under Normal Conditions
TPL-002-0 — System Performance Following Loss of a Single BES Element
TPL-003-0 — System Performance Following Loss of Two or More BES Elements
TPL-004-0 — System Performance Following Extreme BES Events

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Flowgate:**

1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

**Available Flowgate Capability (AFC):** A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, and less a Transmission Reliability Margin.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system facilities removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs are used to determine Available Transfer Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**
2. **Number:** MOD-030-1
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
   - **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for ATC Paths.
   - **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate ATCs for ATC Paths.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID). [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.2.1.** Define if the source used for ATC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Identify Flowgates used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Element/Contingency combinations with an OTDF greater than 3% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.

**R2.1.2.** Results of a first contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements/Contingency combinations with an Outage Transfer Distribution Factor (OTDF) greater than 3% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.

**R2.1.3.** Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.

**R2.1.4.** Any limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.2.** At a minimum, update the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.

**R2.3.** At a minimum, update the list of Flowgates to create, modify, or delete external Flowgates that have been requested within thirty calendar days from the request.

**R2.4.** Determine the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, update the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the updated TFCs within seven calendar days of their determination.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains Facility Ratings specified by the Transmission Owners and Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and facilities161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include all expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the period calculated for the Transmission Service Provider’s area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.3, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of base generation to load, for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed, based on:

**R6.1.1.** For on-peak intra-day and on-peak next-day AFCs:

6.1.1.1.Load forecast for the on-peak period calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load

6.1.1.2.Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.2.** For off-peak intra-day and off-peak next-day AFCs:

6.1.2.1.Load forecast for the off-peak period calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load.

6.1.2.2.Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.3.** For days two through 31AFCs:

6.1.3.1. Load forecast for the day calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load.

6.1.3.2.Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.4.** For months two through 13 AFCs:

6.1.4.1.Load forecast for the month calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load.

6.1.4.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of base generation to load and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider’s area not included in the model.

**R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts, not included in the model and having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area not included in the model.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that are not included in the model and having a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

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[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled that are not included in the model for the Transmission Service Provider's area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that are not included in the model and have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that are not included in the model for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that are not included in the model and have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

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[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC – ETC_{Fi} – CBM_i – TRM_i + Postbacks_{Fi} + Counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of Firm Transmission Service for that period, as defined in Business Practices.

**$Counterflows_{Fi}$** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC – ETC_{Fi} – ETC_{NFi} – CBM_{Si} – TRM_{Ui} + Postbacks_{NFi} + Counterflows$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Flowgate Capability for the ATC Path for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks$_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of Non-Firm Transmission Service for that period, as defined in Business Practices.

**Counterflows$_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC at a minimum on the following frequency: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R10.1.** For hourly AFC, once per day.

**R10.2.** For daily AFC, once per week.

**R10.3.** For monthly ATC, once a month.

**R11.** When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$TC = \min(P)$$

$$P = \{PTC_1, PTC_2, \ldots PTC_n\}$$

$$PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either 'Available' or 'Total').

**P** is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or PTDF Flowgate.

**PTC$_n$** is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n*.

**FC$_n$** is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

**DF$_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**M5.** The Transmission Operator shall provide evidence (such as data and models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs) that it updated the TFCs for each Flowgate at least once per calendar year. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

**M13.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ETC included the elements described in R6. (R6)

**M14.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ETC included the elements described in R7. (R7)

**M15.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm AFC used the algorithm and the elements described in R8 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R8)

**M16.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm AFC used the algorithm and the elements described in R9 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated ATC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Transfer Capabilities follows the procedure described in R11. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R6, R7, R8, R9, and R10 for the most recent calendar year plus current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications

- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2. | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2. |
| R2. | The Transmission Operator has not updated its list of external Flowgates for more than two consecutive quarters but not more than three consecutive quarters.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than three but not more than four consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of | The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than four but not more than five consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider | The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than five consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its list of internal Flowgates for two or more consecutive years.<br>**OR**<br>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.<br>**OR** |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | their determination, but is has not been more than 21 days (three weeks) since their determination. | with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. | The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination. |
| R3. | The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator did not update the Transmission model per the schedule specified in R3.<br>**OR**<br>The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>**OR**<br>The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>**OR**<br>The Transmission operator did |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | not include in the Transmission model detailed modeling data and topology at least three contiguous busses of the BES for more than one adjacent Reliability Coordinator area.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. |
| R4. | N/A | N/A | N/A | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not use the model provided by the Transmission Operator.<br>**OR**<br>The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.<br>**OR**<br>The Transmission Service provider did not use AFC |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | provided by a third party. |
| R6. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R6 when determining non-firm ETC, or used additional elements. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R7 when determining firm AFC, or used additional elements. |
| R8. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements. |
| R9. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R9. |
| R10 | For Hourly, the Transmission Service provider did not calculate for more than 24 hours but not more than 48 hours. **OR** For Daily, the Transmission Service provider did not calculate for more than 7 calendar days but not more than 14 calendar days. **OR** | For Hourly, the Transmission Service provider did not calculate for more than 48 hours but not more than 72 hours. **OR** For Daily, the Transmission Service provider did not calculate for more than 14 calendar days but not more than 21 calendar days. **OR** | For Hourly, the Transmission Service provider did not calculate for more than 72 hours but not more than 96 hours. **OR** For Daily, the Transmission Service provider did not calculate for more than 21 calendar days but not more than 28 calendar days. | For Hourly, the Transmission Service provider did not calculate for more than 96 hours. **OR** For Daily, the Transmission Service provider did not calculate for more than 28 calendar days **OR** For Monthly, the Transmission Service provider did not |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | For Monthly, the Transmission Service provider did not calculate for 31 or more calendar days, but less than 60 calendar days. | For Monthly, the Transmission Service provider did not calculate for 60 or more calendar days, but less than 90 calendar days. | **OR**<br>For Monthly, the Transmission Service provider did not calculate for 90 or more calendar days, but less than 120 calendar days. | calculate for 120 or more calendar days. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R11. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

### Flowgate:

1.) A portion of~~designated point on~~ the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated ~~that will respect all~~ System Operating Limit~~s for that Flowgate~~.

**Available Flowgate Capability (AFC):** A measure of t~~T~~he flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, and less a Transmission Reliability Margin.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more ~~a specific~~ system ~~facility~~ facilities removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on ~~facility~~ Facility ~~ratings~~Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total ~~Transmission~~ Flowgate Capability to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs are used to determine Available Transfer ~~Transmission~~ Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-1**

3. **Purpose:** To increase consistency and ~~transparency~~ reliability in the development and documentation of transfer capability calculations for short-term ~~Transmission services~~use performed by entities using the Flowgate Methodology to support ~~reliable~~ analysis and system operations.

4. **Applicability:**

   **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for ATC ~~Posted~~ Paths.

   **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate ATCs for ~~Posted~~ ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that ~~all six (~~MOD-001-1, ~~MOD-004-1, MOD-008-1,~~ MOD-028-1, MOD-029-1 ~~,~~ and MOD-030-1~~)ATC-related standards~~ are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service ~~provider~~ Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID)~~the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations~~. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** -The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.2.1.** Define if the source used for ATC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generati~~on~~ors, the ATCID must identify how these generators participate in the group.~~.~~

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: ~~Lower~~Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Identify Flowgates ~~for~~ used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first C~~c~~ontingency transfer analysis for ATC Paths internal to a ~~t~~Transmission~~'s~~ O~~o~~perator's system up to the path capability such that at a minimum the first three limiting E~~e~~lement/C~~c~~ontingency combinations with an OTDF greater than 3% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.

~~**R1.1.1.** Any Facility within the Transmission Operator's area based on thermal, stability or voltage limits is a Flowgate.~~

**R2.1.2.** Results of a first c~~All first C~~ontingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements/Contingency combinations with an Outage Transfer Distribution Factor (OTDF) greater than 3% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use Contingency assumptions~~Contingencies~~ consistent with those~~the Contingencies~~ used in operations studies and planning studies for the applicable time periods.

**R2.1.3.** Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.~~OR any limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where~~

**R2.1.4.** Any limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or

- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.2.** At a minimum, update the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year~~quarter~~.

**R2.3.** At a minimum, update the list of Flowgates to create, modify, or delete external Flowgates that have been requested within thirty calendar days from the request.

**R2.4.** Determine the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, update the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the updated TFCs within seven calendar days of their determination.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a~~use a~~ Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains Facility Ratings specified by the Transmission Owners and Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and facilities161kV or below is allowed.

~~**R2.5.**~~Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination aAreas.~~for at least three contiguous busses of the Bulk Electric System directly and synchronously connected to the tie-lines into the systems of each adjacent Reliability Coordinator Area.~~

**R3.5.** ~~Contains modeling data and topology (or equivalent representation) for synchronous Facilities beyond three busses.~~

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows~~Use assumptions consistent with the assumptions used in operations studies and planning studies for the applicable time periods, including~~: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

~~**R3.1.**Contingencies.~~

~~**R3.2.**Modeling the impact of point-to-point reservations as follows:~~

- If the source, as specified in the ATCID, has been ~~specified~~ identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.

- If the source, as specified in the ATCID, has been identified~~specified~~ in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation~~modeled~~ in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified~~specified~~ in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation~~modeled~~ in the Transmission Service Provider's Transmission model, use the immediately~~interface point with the~~ adjacent Balancing Authority associated with the~~upstream~~ Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified~~specified,~~ in the reservation use the immediately ~~interface point with the~~ adjacent Balancing Authority associated with the~~upstream~~ Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified~~specified~~ in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified~~specified~~ in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation~~modeled~~ in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified~~specified~~ in the reservation and the point can~~-~~not be mapped to a discretely modeled point or an "equivalence" representation~~modeled~~ in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated~~interface point~~ with the ~~adjacent downstream~~ Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified ~~specified,~~ in the reservation use the immediately adjacent Balancing Authority associated ~~interface point~~ with the ~~adjacent downstream~~ Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**~~R5.1.~~R5.2.** Include all expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the period calculated for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**~~R5.2.~~R5.3.** For external ~~(third-party)~~ Flowgates, identified in R2.1.3, use ~~any~~ the AFC ~~for each specific Flowgate~~ provided by ~~that~~ the Transmission Service Provider that calculates AFC for that Flowgate~~third party as the AFC for that Flowgate~~.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of ~~F~~firm Network Integration Transmission~~and Native Load~~ Service, including the impacts of base generation to load, for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed, based on:

**R6.1.1.** For on-peak intra-day and on-peak next-day AFCs:

6.1.1.1. ~~Peak~~ Load forecast for the on-peak period calculated, consistent with that used for planning and operations for applicable time periods, including ~~native~~ Native ~~load~~ Load and network service ~~load~~ Load

6.1.1.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.2.** For off-peak intra-day and off-peak next-day AFCs:

6.1.2.1. ~~Peak~~ Load forecast for the off-peak period calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service ~~Load~~ ~~l~~Load~~-~~.

6.1.2.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.3.** For days two through 31AFCs:

~~6.1.3.1.1~~6.1.3.1. ~~Peak~~ Load forecast for the day calculated, consistent with that used for planning and operations for applicable time periods, including ~~native~~ Native ~~load~~ Load and network service ~~load~~ Load.

6.1.3.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.1.4.** For months two through 13 AFCs:

6.1.4.1. ~~Peak~~ Load forecast for the month calculated, consistent with that used for planning and operations for applicable time periods, including ~~native~~ Native ~~load~~ Load and network service ~~load~~ Load.

6.1.4.2. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of base generation to load and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**~~R6.2.~~R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area not included in the model.

**~~R6.3.~~R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts, not included in the model and haveing a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider ~~in excess of 3%~~ for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed. ~~The impact of any Grandfathered firm contracts expected to be scheduled for the Transmission Service Provider's area not included in the model.~~

**R6.5.** The impact of any Grandfathered firm obligations~~contracts~~ expected to be scheduled or expected to flow ~~not included in the model in excess of 3%~~ for ~~all adjacent~~the Transmission Service Provider's area not included in the model~~and any other Transmission Service Providers with which coordination agreements have been executed~~.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that are not included in the model and haveing a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

**~~R5.4.~~**

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled that are not included in the model for the Transmission Service Provider's area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that are not included in the model and have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

procedure used by the Transmission Service Provider~~in excess of 3%~~ for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that are~~contracts~~ not included in the model for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that are~~contracts~~ not included in the model ~~i~~and have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider~~n excess of 3%~~ for all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (~~i.e.,Secondary~~i.e., secondary ~~S~~service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

~~**R6.4.**~~

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + Counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period~~,~~.

**TFC** is the Total Flowgate Capability of the Flowgate~~,~~.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period~~,~~.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period~~,~~.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period~~,~~ .

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**Postbacks$_{Fi}$** are ~~adjustments~~ changes to firm AFC due to a change in the use of Firm Transmission Service~~postbacks~~ for that period, as defined in Business Practices~~, and~~.

**Counterflows$_{Fi}$** are adjustments to firm ~~ATC~~ AFC as determined by the Transmission Service Provider and ~~described~~ specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC – ETC_{Fi} – ETC_{NFi} – CBM_{Si} – TRM_{Ui} + Postbacks_{NFi} + Counterflows$$

**Where:**

**ATC$_{NF}$** is the non-firm Available Flowgate Capability for the ~~Posted~~ ATC Path for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC$_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**ETC$_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**CBM$_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**TRM$_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks$_{NF}$** are ~~adjustments~~ changes to non-firm Available Flowgate Capability due to ~~to~~ a change in the use of Non-Firm Transmission Service~~postbacks~~ for that period, as defined in ~~business~~ Business ~~practices~~Practices.

**Counterflows$_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and ~~described~~ specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC at a minimum on the following frequency: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R10.1.** For hourly AFC, once per day.

**R10.2.** For daily AFC, once per week.

**R10.3.** For monthly ATC, once a month.

~~**M1.**~~**R11.** When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values~~Flowgate AFCs to ATCs (and TFCs to TTCs) for Posted Paths~~ based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$\cancel{TC = \min\{PTC_1, PTC_2, \ldots PTC_n\} \text{ and } PTC_n = \frac{FC_n}{DF_{np}}}$$

$$TC = \min(P)$$

$$P = \{PTC_1, PTC_2, \ldots PTC_n\}$$

$$PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either 'Available' or 'Total').

**P** is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or PTDF Flowgate.

**$PTC_n$** is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n.*

**$FC_n$** is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

**$DF_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year~~quarter~~. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**~~M4.~~M5.** The Transmission Operator shall provide evidence (such as data and models) that it determined the TFC for each Flowgate as defined in R2.~~3~~4. (R2.~~3~~4)

**~~M5.~~M6.** The Transmission Operator shall provide evidence (such as logs) that it updated the TFCs for each Flowgate at least once per calendar year. (R2.~~4~~5)

**~~M6.~~M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.~~5~~6)

**~~M7.~~M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M9.** ~~The Transmission Service Provider shall provide evidence (such as written documentation and studies) that the assumptions used in AFC calculation were consistent with those used in operations and planning studies for the same period. (R4.1)~~The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator’s models in calculating AFC. (R5.1)

**~~M10.~~M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.~~1~~2)

**~~M11.~~M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.~~2~~3)

**~~M12.~~M13.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ETC included the elements described in R6. ~~and did not include any additional elements.~~ (R6)

**~~M13.~~M14.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ETC included the elements described in R7~~ and did not include any additional elements~~. (R7)

**~~M14.~~M15.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm AFC used the algorithm and the elements described in R8 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R8)

**~~M15.~~M16.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm AFC used the algorithm and the elements described in R9 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated ATC on the frequency defined in R10. (R10)

**~~M16.~~M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Transfer Capabilities follows the procedure described in R1~~0~~1. (~~R10~~R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2 and R3.

- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R6, R7, R8, R9, and R10 for the most recent calendar year plus current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2.<br>~~N/A~~ | The Transmission Service Provider does not include in its ATCID the ~~criteria for identifying Flowgates to be considered in AFC calculations.~~information described in R1.1 and R1.2. |
| R2. | The Transmission Operator has not updated its list of external Flowgates for more than two consecutive quarters but not more than three consecutive quarters.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than three but not more than four consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider | The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than four but not more than five consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>**OR**<br>The Transmission Operator | The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator has not updated its list of external Flowgates for more than five consecutive quarters.<br>**OR**<br>The Transmission Operator has not updated its list of internal Flowgates for two or more consecutive years.<br>**OR**<br>The Transmission Operator did not determine the TFC for a flowgate as described in |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination. | has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. | R2.~~3~~4.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination. |
| R3. | The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model ~~and one of those Facility Ratings was used (or should have been used) to establish a TFC for one or more flowgates~~.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model ~~and two to five of those Facility Ratings were used (or should have been used) to establish a TFC for one or more flowgates~~.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model ~~and six to ten of those Facility Ratings were used (or should have been used) to establish a TFC for one more flowgates~~.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator did not update the Transmission model per the schedule specified in R3.<br>**OR**<br>The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model ~~and eleven or more of those Facility Ratings were used (or should have been used) to establish a TFC for one or more flowgates~~.<br>**OR**<br>The Transmission operator did |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>**OR**<br>The Transmission operator did not include in the Transmission model detailed modeling data and topology at least three contiguous busses of the BES for more than one adjacent Reliability Coordinator area.<br><br>A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. |
| R4. | N/A | N/A | N/A | The Transmission Service Provider did not ~~use assumptions consistent with those used in operations and planning studies for the same period.~~represent the impact of Transmission Service as described in R4. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. ~~in the~~ | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.~~in the~~ | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.~~in the~~ | The Transmission Service Provider did not use ~~assumptions consistent with those used in operations and planning studies for the same period~~the model provided by the Transmission Operator.<br>**OR** |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | ~~AFC process.~~ | ~~AFC process.~~ | ~~AFC process.~~ | ~~The Transmission Service Provider did not model reservations as described in R4.1.~~<br>~~**OR**~~<br>The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.~~in the AFC process.~~<br>**OR**<br>The Transmission Service provider did not use AFC provided by a third party. |
| R6. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R6 when determining non-firm ETC, or used additional elements. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R7 when determining firm AFC, or used additional elements. |
| R8. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R9. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R9. |
| R10 | For Hourly, the Transmission Service provider did not calculate for more than 24 hours but not more than 48 hours.<br>**OR**<br>~~f~~For Daily, the Transmission Service provider did not calculate for more than 7 calendar days but not more than 14 calendar days.<br>**OR**<br>~~f~~For Monthly, the Transmission Service provider did not calculate for 31 or more calendar days, but less than 60 calendar days. | For Hourly, the Transmission Service provider did not calculate for more than 48 hours but not more than 72 hours.<br>**OR**<br>~~f~~For Daily, the Transmission Service provider did not calculate for more than 14 calendar days but not more than 21 calendar days.<br>**OR**<br>~~f~~For Monthly, the Transmission Service provider did not calculate for 60 or more calendar days, but less than 90 calendar days. | For Hourly, the Transmission Service provider did not calculate for more than 72 hours but not more than 96 hours~~,~~.<br>**OR**<br>~~f~~For Daily, the Transmission Service provider did not calculate for more than 21 calendar days but not more than 28 calendar days.<br>**OR**<br>~~f~~For Monthly, the Transmission Service provider did not calculate for 90 or more calendar days, but less than 120 calendar days. | For Hourly, the Transmission Service provider did not calculate for more than 96 hours.<br>**OR**<br>~~f~~For Daily, the Transmission Service provider did not calculate for more than 28 calendar days.<br>**OR**<br>~~f~~For Monthly, the Transmission Service provider did not calculate for 120 or more calendar days. |
| ~~R10~~R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in ~~R10~~R11. |

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

## Implementation Plan for Standard MOD-030-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-030-1, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining ATC.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### Modified Standards

This standard incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-030-1 | ■ | | ■ | | | |

### Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

## Summary Consideration of Comments:

The Drafting Team has reviewed the comments and made some changes to the standard to address these comments.

1. As requested by BPA and others, the standard was modified to be clear that MOD-030 does not require conversion of AFC to ATC. While the OASIS Requirements require that ATC be posted, the Drafting Team could not find any reason that AFC must be converted to ATC for reliability. MOD-030 continues to provide the equation to convert AFC to ATC, that shall be used 'when' the conversion occurs, but the NERC standards do not define 'when' that conversion must occur.
2. All VRFs were set to "Lower" in response to industry comments. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
3. A more graded approach was applied to the VSLs where appropriate.
4. During the review of the VSLs and Measures, it was determined that the measures for R6, R7, R8, and R9 did not adequately measure compliance with the requirements. The drafting team updated the measures and VSLs to ensure that they captured the need to have accurate and valid numbers used in the requirements.
5. The standard drafting team has added language to 2.1.1 and 2.1.2 to clarify what is meant by first three limiting element/contingency combinations.
6. The SDT has modified R2.1.1.1 and R2.1.2.1 to respond to the suggestions to acknowledge the use of SPS and has added a new R2.1.4.2 to further define a "credible" limiting Element/Contingency combinations that may be requested for inclusion.
7. The Drafting Team has changed the requirements to use a consistent 5%.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/standards/newstandardsprocess.html.

| Entity | Comment |
| --- | --- |
| Associated Electric Cooperative, Inc. | Again same as MOD-001. If the calculation typically calculates every hour and for some reason an hour is missed the VSL is too high. It should be low. |
| Response: Where possible, the VSLs have been broken into graduated levels rather than only one level. | |
| Bonneville Power Administration | The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make all of the necessary modifications to reflect the removal of the conversion requirement. BPA suggests the following modifications be made to MOD-030-1:<br>o Change the following Requirements and Measures to replace each ATC with AFC:<br>o R1.2 - R1.2.2, R1.2.4, description of the first variable in R9, R10.3, and M17.<br>o Change the Data Retention requirements in the second and fifth dashes to replace each TTC with TFC.<br>o Change the Violation Severity Levels to replace Transfer Capabilities with AFC at R9 Severe VSL.<br>Response: These corrections have been made.<br><br>Additional barriers to an affirmative vote on MOD-030-1 are concerns about adding additional flowgates, which would complicate operation with no benefit in reliability:<br>1. R2.1.1 and R2.1.2 do not take into consideration Special Protection Schemes (SPS) that are utilized within the Western Interconnection, which prevent some contingencies, which initiate use of a SPS, from being the limiting contingency. This can move the limiting contingencies outside the defined Flowgate, but does not require those contingencies to be in a Flowgate to reliably operate the transmission system. As written, additional contingency/limiting elements would need to be defined as Flowgates and unnecessary complexity will be added to operating the transmission system with no increased reliability benefit.<br>Response: R2.1.1.1 and R2.1.2.1 have been modified to include the use of SPS.<br><br>2. BPA has examples of transmission lines operated in series that would require separate Flowgates be defined for each transmission line as R2.1.1 and R2.1.2 are written because, at minimum, the first three limiting Element/contingency combinations are included as Flowgates. In our example, limiting for the most limiting Flowgate protects the others that are in series and should not require additional Flowgates be defined.<br>Response: The Drafting Team has inserted language to address this issue in 2.1.1.2 and 2.1.2.2<br><br>3. If Flowgates are defined based on protecting for multiple contingencies and outage conditions, the limiting element/contingency combinations can move away from the existing monitored Flowgates. Limiting the existing Flowgates can protect the transmission system without adding additional Flowgates.<br>Response: If a flowgate is defined to protect multiple contingencies and outage conditions, then the flowgate that needs to be defined is the most limiting monitored element/contingency pair. Therefore if the most limiting flowgate moves away |

| Entity | Comment |
|---|---|
| | from the existing monitored flowgate then a new flowgate should be defined.<br><br>4. This methodology seems to be more applicable to thermally limited Flowgates than voltage stability or transient stability. BPA has a Flowgate that can be limited by a generation loss and the limitation is reactive margin or voltage dip, rather than a specific element. The existing Flowgate is limited to protect for the generation loss. In this example the limiting contingency is not a Flowgate and the limiting element is not a Flowgate.<br>Response: R2.4 is intended to allow the specification of voltage or stability limited flowgates.<br><br>5. In R2.1.1 and R2.1.2 it is not clear what is meant by the first three limiting element/contingency combinations with an OTDF greater than 3% are included as Flowgates. Here are some possibilities: The limiting elements for the three most limiting contingencies need to be included as Flowgates. The three most limiting elements for the worst contingency need to be included as Flowgates. The three most limiting contingencies need to be included as Flowgates. The three most limiting contingencies and the most limiting elements for each contingency need to be included as Flowgates. An example would be helpful.<br>Response: The standard drafting team has added language to 2.1.1 and 2.1.2 to clarify what is meant by first three limiting element/contingency combinations.<br><br>BPA suggests these Requirements be rewritten in the following manner:<br>R2.1. Identify Flowgates used in the AFC process based, at a minimum, on the following criteria:<br>R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator system up to the path capability such that at a minimum the first three limiting Element/Contingency combinations with an OTDF greater than 3% and within the Transmission Operator system are included as Flowgates, or alternately SOLs and IROLs on a Transmission Operator system are included as Flowgates.<br>2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements/Contingency combinations with an Outage Transfer Distribution Factor (OTDF) greater than 3% and within the Transmission Operator system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology, or alternately SOLs and IROLs on a Transmission Operator system are included as Flowgates.<br>2.1.2.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.3. Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.<br>R2.1.4. Any credible limiting element/contingency combination within the Transmission model that has been |

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| | requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:<br>2.1.4.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and<br>- Any generator within the Transmission Service Provider area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or<br>- A transfer from any Balancing Area within the Transmission Service Provider area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.<br>Response: The SDT has modified R2.1.1.1 and R2.1.2.1 to respond to the suggestions to acknowledge the use of SPS and has added a new R2.1.4.2 to further define a "credible" limiting Element/Contingency combinations that may be requested for inclusion. |
| Response: Please see in-line responses. | |
| CenterPoint Energy | ERCOT filed comments to the SDT that ATC, TTC, CBM, and TRM are not applicable within ERCOT operations and that these Standards should have provisions that make it clear that these requirements apply only within market structures in which they are pertinent were ignored by the SDT. These standards should not apply to ERCOT, thus our negative vote. |
| Response: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any path for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT, and would not require implementation of any methodology, including this standard. | |
| FirstEnergy Energy Delivery | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br>CBM & TRM - MARKET AREAS: FE supports the drafting team approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc.<br>FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely as within both market and non-market areas as the PC and RC would be appropriate in both. Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br>Response: Please see responses contained in the CBM and TRM comment reports.<br><br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have |

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| | been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the Solicit Public Comments on Draft Standard (Step 6) of the NERC SDP is to Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus. Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br>Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.<br><br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>o Either the Planning Coordinator (PC) or Reliability Coordinator (RC) should replace the Transmission Operator (TOP) as having ultimate responsibility for the requirements in R2 and R3. The PC or RC will work with their associated Transmission Planners and/or TOPs to obtain the necessary information to properly identify flowgates and develop the proper transmission models.<br>Response: R2 & R3 will remain the responsibility of the Transmission Operator. The functions, responsibilities, and tasks of the Transmission Operator and Transmission Service Provider are defined in the NERC Reliability Functional Model. The Transmission Operator function ensures the real-time operating reliability of the transmission assets within a reliability area. The Drafting Team believes that the function of ensuring operating reliability includes identifying and maintaining flowgates per requirements R2 and developing the transmission models per requirement R3, and therefore is the Transmission Operator's responsibility.<br><br>o Also with regard to R2 and R3, we believe that there is too much detail in the subrequirements and that there may be other methods to identify flowgates and develop transmission models. These requirements should focus on the what and not the how.<br>Response: The Drafting Team believes that in order to maintain the reliability of the flowgate methodology, a minimum amount of flowgates need to be determined based on standard criteria. Please note that this is only used to determine the minimum amount of flowgates to be added, other processes can be used to add additional flowgates.<br><br>o The definitions for AFC and Flowgate Methodology should include mention of Postbacks and Counterflows which are significant factors in calculating AFC and ATC (see the algorithm of Requirement R8).<br>Response: The SDT has modified the definitions accordingly. |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Great River Energy</td><td>GRE supports BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period based on the significance of the comments submitted during the previous commenting periods.</td></tr>
<tr><td colspan="2">Response: Please see responses to BPA, PJM, and MISO.</td></tr>
<tr><td>Hydro One Networks, Inc.</td><td>Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighbouring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained.<br><br>Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.<br><br>In addition we offer the following comments to the specific Standard MOD-030:<br><br>o Some requirements (e.g. R2.1.1) stipulate that flowgates having a 3% OTDF are to be included for AFC calculation; whereas other requirements (e.g. R2.1.4.1) stipulate that flowgates with a 5% PTDF or OTDF are to be included. Despite this apparent inconsistency, after having these two sets of threshold stipulated and with requirements that link to the curtailment threshold (e.g. R6.2, R6.4 and R6.1), the standard makes provisions (e.g. 2.1.4.1, footnotes to R6.2, R6.4 and R6.6) that allow inclusion of flowgates at responses lower than these thresholds. The apparently conflicting requirements combined with the provisions to apply lower thresholds render the standard not measurable and enforceable.<br><br>Response: The Drafting Team has changed the sub-requirements under R2 to use a consistent 5%. The SDT intends for TOs to be able to use more conservative lower thresholds in both defining flowgates and including the impacts of adjacent reservations, if they so choose. The minimum thresholds were established to ensure the standards are measurable.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Hydro-Quebec TransEnergie</td><td>Requirement 2.1.1 asks for an "OTDF greater than 3% and within the Transmission Operator system are included as Flowgates." Requirement 2.1.4.1 asks for "has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF)". The same requirement states that "The Transmission Operator may utilize distribution factors less than 5% if desired." Only one factor shall be used in all the standard and no allowance for not following it should be made. Moreover other standards ask for 5%!</td></tr>
<tr><td colspan="2">Response: The Drafting Team has changed the requirements to use a consistent 5%.</td></tr>
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| Kansas City Power & Light Co. | Requirement R2 requires the Transmission Operator to perform functions that are currently performed by the SPP Transmission Service Provider for KCPL. This requirement should be revised to "or Transmission Service Provider" after "Transmission Operator" so that the entity could perform these tasks. |
| Response: R2 will remain the responsibility of the Transmission Operator. The functions, responsibilities, and tasks of the Transmission Operator and Transmission Service Provider are defined in the NERC Reliability Functional Model. The Transmission Operator function ensures the real-time operating reliability of the transmission assets within a reliability area. The SDT believes that the function of ensuring operating reliability includes identifying and maintaining flowgates per requirement R2 and this is a Transmission Operator responsibility. While KCPL may have delegated tasks of the Transmission Operator function to SPP, they can not delegate the responsibility. The Transmission Operator's responsibility to other entities that it appears KCPL has delegated to SPP is the coordination of available transfer capability with the Transmission Service Provider ( Transmission Service Provider). The Transmission Service responsibility definition in the Functional Model is "administers the transmission tariff and provides transmission services under applicable transmission service agreements," (for example, the pro forma tariff). The requirement R2 is not a responsibility of the Transmission Service Provider. | |
| National Grid | Some requirements (e.g. R2.1.1) stipulate that flowgates having a 3% OTDF are to be included for AFC calculation; whereas other requirements (e.g. R2.1.4.1) stipulate that flowgates with a 5% PTDF or OTDF are to be included. Despite this apparent inconsistency, after having these two sets of threshold stipulated and with requirements that link to the curtailment threshold (e.g. R6.2, R6.4 and R6.1), the standard makes provisions (e.g. 2.1.4.1, footnotes to R6.2, R6.4 and R6.6) that allow inclusion of flowgates at responses lower than these thresholds. The apparently conflicting requirements combined with the provisions to apply lower thresholds render the standard not measurable and enforceable. |
| Response: The Drafting Team has changed the sub-requirements under R2 to use a consistent 5%. The Drafting Team intends for Transmission Operators to be able to use more conservative lower thresholds in both defining flowgates and including the impacts of adjacent reservations, if they so choose. The minimum thresholds were established to ensure the standards are measurable. | |
| New Brunswick Power Transmission Corporation | The conflicting requirements combined with the provisions to apply lower thresholds render this standard not measurable and enforceable. |
| Response: The Drafting Team has changed the sub-requirements under R2 to use a consistent 5%. The Drafting Team intends for Transmission Operators to be able to use more conservative lower thresholds in both defining flowgates and including the impacts of adjacent reservations, if they so choose. The minimum thresholds were established to ensure the standards are measurable. | |
| Northeast Utilities | Some requirements (e.g. R2.1.1) stipulate that flowgates having a 3% OTDF are to be included for AFC calculation; whereas other requirements (e.g. R2.1.4.1) stipulate that flowgates with a 5% PTDF or OTDF are to be included. Despite this apparent inconsistency, after having these two sets of threshold stipulated and with requirements that link to the curtailment threshold (e.g. R6.2, R6.4 and R6.1), the standard makes provisions (e.g. 2.1.4.1, footnotes to R6.2, R6.4 and R6.6) that allow inclusion of flowgates at responses lower than these thresholds. The apparently conflicting requirements combined with the provisions to apply lower thresholds render the standard not measurable and enforceable. |
| Response: The Drafting Team has changed the sub-requirements under R2 to use a consistent 5%. The Drafting Team intends for Transmission Operators to be able to use more conservative lower thresholds in both defining flowgates and including the impacts of adjacent | |

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| reservations, if they so choose. The minimum thresholds were established to ensure the standards are measurable. | |
| Portland General Electric Co. | The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make all of the necessary modifications to reflect the removal of the conversion requirement. BPA suggests the following modifications be made to MOD-030-1:<br>o Change the following Requirements and Measures to replace each ATC with AFC:<br>o R1.2 - R1.2.2, R1.2.4, description of the first variable in R9, R10.3, and M17.<br>o Change the Data Retention requirements in the second and fifth dashes to replace each TT with TF.<br>o Change the Violation Severity Levels to replace Transfer Capabilities with AFC at R9 Severe VSL.<br>Response: These corrections have been made.<br><br>Additional barriers to an affirmative vote on MOD-030-1 are concerns about adding additional flowgates which would complicate operation with no benefit in reliability:<br>1. R2.1.1 and R2.1.2 do not take into consideration Special Protection Schemes (SPS) that are utilized within the Western Interconnection, which prevent some contingencies, which initiate use of a SPS, from being the limiting contingency. This can move the limiting contingencies outside the defined Flowgate, but does not require those contingencies to be in a Flowgate to reliably operate the transmission system. As written, additional contingency/limiting elements would need to be defined as Flowgates and unnecessary complexity will be added to operating the transmission system with no increased reliability benefit.<br>Response: R2.1.1.1 and R2.1.2.1 have been modified to include the use of SPS.<br><br>2. BPA has examples of transmission lines operated in series that would require separate Flowgates be defined for each transmission line as R2.1.1 and R2.1.2 are written because, at minimum, the first three limiting Element/contingency combinations are included as Flowgates. In our example, limiting for the most limiting Flowgate protects the others that are in series and should not require additional Flowgates be defined.<br>Response: The Drafting Team has inserted language to address this issue in 2.1.1.2 and 2.1.2.2<br><br>3. If Flowgates are defined based on protecting for multiple contingencies and outage conditions, the limiting element/contingency combinations can move away from the existing monitored Flowgates. Limiting the existing Flowgates can protect the transmission system without adding additional Flowgates.<br>Response: If a flowgate is defined to protect multiple contingencies and outage conditions, then the flowgate that needs to be defined is the most limiting monitored element/contingency pair. Therefore if the most limiting flowgate moves away from the existing monitored flowgate then a new flowgate should be defined.<br><br>4. This methodology seems to be more applicable to thermally limited Flowgates than voltage stability or transient stability. BPA has a Flowgate that can be limited by a generation loss and the limitation is reactive margin or voltage |

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| | dip, rather than a specific element. The existing Flowgate is limited to protect for the generation loss. In this example the limiting contingency is not a Flowgate and the limiting element is not a Flowgate.<br>Response: R2.4 is intended to allow the specification of voltage or stability limited flowgates.<br><br>5. In R2.1.1 and R2.1.2 it is not clear what is meant by the first three limiting element/contingency combinations with an OTDF greater than 3% are included as Flowgates. Here are some possibilities: The limiting elements for the three most limiting contingencies need to be included as Flowgates. The three most limiting elements for the worst contingency need to be included as Flowgates. The three most limiting contingencies need to be included as Flowgates. The three most limiting contingencies and the most limiting elements for each contingency need to be included as Flowgates. An example would be helpful.<br>Response: The standard drafting team has added language to 2.1.1 and 2.1.2 to clarify what is meant by first three limiting element/contingency combinations.<br><br>BPA suggests these Requirements be rewritten in the following manner:<br>R2.1. Identify Flowgates used in the AFC process based, at a minimum, on the following criteria:<br>R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator system up to the path capability such that at a minimum the first three limiting Element/Contingency combinations with an OTDF greater than 3% and within the Transmission Operator system are included as Flowgates, or SOLs and IROLs on a Transmission Operator system are included as Flowgates..<br>2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>Response: The SDT has modified R2.1.1.1 and R2.1.2.1 to respond to the suggestions to acknowledge the use of SPS and has added a new R2.1.4.2 to further define a “credible” limiting Element/Contingency combinations that may be requested for inclusion. |
| Response: Please see in-line responses. | |
| Potomac Electric Power Co. | Potomac Electric agrees with the comments of PJM distributed to the ballot body. I will not repeat them here, but do include the headings:<br>I. The ATC MOD standards should have been sent out for comment not pre-ballot posting.<br>II. Depth of the ATC MOD standards is excessive.<br>III. Determining Violation Risk Factors is incorrect.<br>IV. Determining Violation Severity Levels is incomplete. |
| Response: Please see PJM response. | |
| PP&L, Inc. | The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make all of the necessary modifications to reflect the removal of the conversion requirement. It is suggested that the |

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| | following modifications be made to MOD-030-1:<br>o Change the following Requirements and Measures to replace each ATC with AFC:<br>o R1.2 - R1.2.2, R1.2.4, description of the first variable in R9, R10.3, and M17.<br>o Change the Data Retention requirements in the second and fifth dashes to replace each TTC with TFc.<br>o Change the Violation Severity Levels to replace Transfer Capabilities with AFC at R9 Severe VSL.<br>Response: These corrections have been made.<br><br>Additional barriers to an affirmative vote on MOD-030-1 are concerns about adding additional flowgates which would complicate operation with no benefit in reliability:<br>o R2.1.1 and R2.1.2 do not take into consideration Special Protection Schemes (SPS) that are utilized within the Western Interconnection, which prevent some contingencies, which initiate use of a SPS, from being the limiting contingency. This can move the limiting contingencies outside the defined Flowgate, but does not require those contingencies to be in a Flowgate to reliably operate the transmission system.<br>Response: R2.1.1.1 and R2.1.2.1 have been modified to include the use of SPS.<br><br>o As written, additional contingency/limiting elements would need to be defined as Flowgates and unnecessary complexity will be added to operating the transmission system with no increased reliability benefit. There are examples of transmission lines operated in series that would require separate Flowgates be defined for each transmission line as R2.1.1 and R2.1.2 are written because, at minimum, the first three limiting Element/contingency combinations are included as Flowgates. In our example, limiting for the most limiting Flowgate protects the others that are in series and should not require additional Flowgates be defined. If Flowgates are defined based on protecting for multiple contingencies and outage conditions, the limiting element/contingency combinations can move away from the existing monitored Flowgates. Limiting the existing Flowgates can protect the transmission system without adding additional Flowgates. This methodology seems to be more applicable to thermally limited Flowgates than voltage stability or transient stability. A Flowgate exists that can be limited by a generation loss and the limitation is reactive margin or voltage dip, rather than a specific element. The existing Flowgate is limited to protect for the generation loss. In this example the limiting contingency is not a Flowgate and the limiting element is not a Flowgate.<br>Response: If a flowgate is defined to protect multiple contingencies and outage conditions, then the flowgate that needs to be defined is the most limiting monitored element/contingency pair. Therefore if the most limiting flowgate moves away from the existing monitored flowgate then a new flowgate should be defined.<br><br>R2.4 is intended to allow the specification of voltage or stability limited flowgates.<br><br>o In R2.1.1 and R2.1.2 it is not clear what is meant by the first three limiting element/contingency combinations with an OTDF greater than 3% are included as Flowgates. Here are some possibilities: The limiting elements for the three |

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| Response: Please see in-line responses. | |
| Public Service Electric and Gas Co. | PSE&G votes NO for the reasons expressed in PJM comments. |
| Response: Please see PJM response. | |
| Sierra Pacific Power Co. | Not used as a methodology. |
| Response: No response needed. | |
| Southern Company Services, Inc. | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Westar Energy | R1.1 Should be criteria used by the Transmission Provider not Operator. R2.1.1 and R2.1.2 should read ... OTDF greater than or equal to 3%... R2.1.4.1 Why now use terminology of ... at least 5%...? |
| Response: The functions, responsibilities, and tasks of the Transmission Operator and Transmission Service Provider are defined in the NERC Reliability Functional Model. The Transmission Operator function ensures the real-time operating reliability of the transmission assets within a reliability area. The SDT believes that the function of ensuring operating reliability includes identifying and maintaining flowgates is the Transmission Operator's responsibility.<br><br>The Drafting Team has changed the requirements to use a consistent 5%. | |
| Western Area Power Administration | No comment. |
| Response: No response needed. | |
| Independent Electricity System Operator | The requirements are not clearly drafted because there are multiple thresholds provided throughout the document pertaining to treatment of flowgates - 3% in some cases and 5% in other cases - inconsistent with the 5% threshold that is normally used in the industry and TLR practices.<br>Requirement R2.1.1 is new/significantly revised from previous requirement under a different number. It says: Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator system up to the path capability such that at a minimum the first three limiting Element/Contingency combinations with an OTDF greater than 3% and within the Transmission Operator system are included as Flowgates. The question is why 3%? Even if we assume that it tries to draw consistency with the curtailment threshold for flowgate response, it should be 5%, not 3%. There is no basis for provided this, and now the industry is asked to vote on this new requirement. In the SDT response to previous comments, the STD |

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| | indicated that it would provide explanation on the 3% but there isn't any provided in the current draft standards.<br>Same comment for R2.1.2. Additionally, this standard has also been substantively revised since the last posting. It really should have been posted for another round of comment before being sent to balloting, even allowing for the assumption that the majority of the industry does not have any major issues with the changes. |
| Response: The SDT has changed the sub-requirements under R2 to use a consistent 5%. The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| ISO New England, Inc. | Some requirements (e.g. R2.1.1) stipulate that flowgates having a 3% OTDF are to be included for AFC calculation; whereas other requirements (e.g. R2.1.4.1) stipulate that flowgates with a 5% PTDF or OTDF are to be included. Despite this apparent inconsistency, after having these two sets of threshold stipulated and with requirements that link to the curtailment threshold (e.g. R6.2, R6.4 and R6.1), the standard makes provisions (e.g. 2.1.4.1, footnotes to R6.2, R6.4 and R6.6) that allow inclusion of flowgates at responses lower than these thresholds. The apparently conflicting requirements combined with the provisions to apply lower thresholds render the standard not measurable and enforceable. |
| Response: The SDT has changed the sub-requirements under R2 to use a consistent 5%. The SDT intends for Transmission Operators to be able to use more conservative lower thresholds in both defining flowgates and including the impacts of adjacent reservations, if they so choose. The minimum thresholds were established to ensure the standards are measurable. | |
| New York Independent System Operator | The NYISO does not employ a flowgate-based methodology but is voting against the proposed standard for the reasons set forth in its general comments in response to MOD-001, i.e., the proposed standard is unnecessarily detailed and prescriptive (especially with respect to its mandates regarding the frequency of recalculations), includes unduly harsh violation risk factors that are inconsistent with NERC own policies, and needs to include more graduated violation severity levels.<br>The NYISO also supports the NPCC comment that this proposed standard appears to include internal inconsistencies that render it not measurable and enforceable. |
| Response: Please see MOD-001 and NPCC responses. | |
| PJM Interconnection, L.L.C. | PJM believes no requirement from the set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in |

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| | the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br><br>NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards need to be developed with a more graded implementation for several requirements.<br>The VSLs for several requirements do not consistently include the graded degree of achieving compliance.<br>To the extent that reliability and transparency can be maintained in the event that the entity does not meet the measures the VSL is often excessive. Some VSLs do not recognize the potential varying level of non-compliance with the requirement. With these requirements there are several instances where the VSLs should have incorporated the following distinctions:<br>• Recognizing gross violation of the requirement – for example the entity's program ignores the requirement.<br>• Recognizing programmatic issues exist with the implementation of the requirement leading failure to meet some of the requirement. For example if only 167 hours of hourly ATC values instead of 168 hours are calculated it would be a violation with a severe sanction indicating that reliability was severely affected. The actual impact being minimal since customers can only reserve hourly ATC for 24 to 48 hours in the future out of the 168 hours.<br>It is clear that the SDT recognized differences in severity levels in some of the requirements such as MOD001 requirement 7. This was accomplished by specifying timeframes and numbers of instances of not meeting the requirements. However the VSLs in several instances throughout the standard(s) do not reflect this approach. The SDT should continue with a more graded implementation of VSLs for:<br>MOD030-1: R6, R7, R8, R9, & R11<br>Response: The Drafting Team has modified the VSLs to be more graded for R6, R7, R8, and R9. Since R11 is simple math and is either implemented correctly or it is not, the Drafting Team does not beleive grading is needed.<br><br>• Definitions: AFC and Flowgate Methodology definitions should include the components postbacks, counterflows, and generator to load impacts separately.<br>Response: The SDT has modified the definitions to include Postbacks and Counterflows. The generation to load impacts are included as a part of ETC and therefore will not be added to the definitions separately.<br><br>The ATC MOD standards should have been sent out for comment not pre-ballot posting.<br>Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.<br><br><u>Requirement 1</u><br>• The Measure M1 and associated VSL for R1 need to have a more graded approach. The current VSL considers that missing a couple of mappings to the model in R1.2 is a high VSL. This sanction is too severe because there is no associated affect on reliability |

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| | Response: The drafting team has graded the VSL.<br><br>• R1.2 and R4. PJM is in agreement with the clarification that source and sink for purposes of transmission service can be POR and POD. However, the requirement is an awkward acknowledgement of the practice of using POR/POD rather than source/sink. PJM believes the language does not clarify the requirements enough. R1.2.1. This causes problems with R4 looking for a point source/sink. Zone to zone transmission service has been in place for years and this standard conflicts with this practice. It is understood through SDT discussion that the POR can substitute for the source and the POD can substitute for the sink, but R4 does not say this and can easily miss this interpretation during audits. Instead this issue is met with the phrase" as specified in the ATCID". If not one would assume that the source or sink must be modeled discretely if a source is specified in the request and that source is not explicitly specified in the ATCID.<br>Response: In R1.2 the standard allows for each Transmission Service Provider to define, in their ATCID, how it handles the source/sink of transmission reservations it receives. For example, the source/sink field can be used or the POR/POD field. In R4, the standard states that the Transmission Service Provider needs to use the source and sink as they define in their ATCID which as we said can be the POR or POD of the reservation.<br><br>Requirement 2<br>• The "Medium" risk factor is inconsistent with NERC's definition of risk factors and should be changed to "Lower" if the requirement is to be retained.<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br><br>• R2.1.1 and R2.1.2 -Should allow ODTF of at least 3% (similar to language in 2.1.4.1)<br>Response: The Drafting Team has changed the sub-requirements under R2 to use a consistent 5% and has modified the language to use "at least", rather than "greater than".<br><br>• R2.1.1.1 and R2.1.2.1 – is ambiguous because the flowgates used in AFC and ATC calculations are a subset of those used in operations and planning studies. Modify or remove R2.1.2.1 because the external flowgates considered in ATC calculations may be much more robust then those used in operations or planning studies. PJM believes that the transfer analyses can use contingencies consistent with operations and planning studies, but believes the analysis should be able |

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| | to include other flowgates that may not be included in the operations and planning studies. The current standard could be interpreted to require that the only flowgates that can be considered for the transfer analysis must have been used in operations and planning studies.<br>Response: Requirements 2.1.1.1 and 2.1.2.1 have been modified to permit more robust assumptions to be used in Operations and Planning studies by limiting the scope to first-contingency analysis, however, it is the intent of the Drafting Team to not permit flowgates to be identified for use in AFC calculations if they would not be identified in Operations and Planning studies.<br><br>• The word “update” used in R2.2, R2.3, and R2.5 should be replaced with “review and update if necessary”.<br>Response: The SDT has modified the standard to replace “update” with “establish” in each of these locations, intending to allow a simple setting of the value without recalculation if appropriate.<br><br>• R2.5.1 and R3.1 should be modified to recognize that these requirements apply only to facility ratings used in the definition of a flowgate used in the AFC and ATC calculations and does not apply to all facility ratings contained in the model. In addition, these requirements should only apply to permanent rating changes not temporary rating changes.<br>Response: The SDT has updated R2.5.1 and R3.1 to reflect these suggestions. However, the drafting team believes that temporary rating changes should be honored, and no change has been made.<br><br>Requirement 3<br>• The “Medium” risk factor is inconsistent with NERC’s definition of risk factors and should be changed to “Lower” if the requirement is to be retained.<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for “a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures.” A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator’s existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br><br>• R3.2 and R3.3 -The update frequency for AFC calculations should be addressed by NAESB.<br>Response: The SDT disagrees, and believe there can be impacts on reliability if these calculations are not performed regularly. |

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| | • R3.4 This standard should not set limits on how models are equivalized. Transmission Operators and regularly use equivalized models that may differ from this requirement. The restriction to 161 kV and below should be removed from the requirement.<br>Response: The SDT disagrees, and believes it is important to establish minimum requirements for how the system should be modeled.<br><br>Requirements 4, 5, and 6<br>• R4, R5, & R6 have the qualifier "as specified in the ATCID". These step by step elements should be eliminated and the reliability requirement clarified.<br>Response: The SDT disagrees and believes that these steps are required to ensure consistency in implementations.<br><br>Requirement 5<br>• The "Medium" risk factor is inconsistent with NERC's definition of risk factors and should be changed to "Lower" if the requirement is to be retained.<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br><br>• R5.2 MOD001 R3.7.1 addresses daily and R3.7.2 addresses monthly , therefore a description of how outages are used in hourly calculations is not required. However, MOD-030 R5.2 requires including all expected outages within scope of model as specified. This requirement should be modified for consistency.<br>Response: MOD-001 requires that an explanation of outage processing be provided; while special rules for handling outage when determining hourly ATC/AFC are not required (it is assumed that an hourly calculation will simply use the outages in effect that hour), they are also not prohibited.<br><br>• R5.2 requires including all expected outages within the scope of model as specified in the ATCID. The intent was to allow outages from a portion of the day to be used to calculate daily AFC and a portion of a daily snapshot to be used for calculating monthly. The description of how outages are applied and including all of those outages has a high chance of noncompliance. A suggestion is to add a time duration for how long an outage can be temporarily excluded (i.e. 7 days for the Lower VSL). PJM believes that the current VSLs for R5.2 are too severe because a TSP that wants to include |

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| | nearly all outages from the NERC SDX outages (this can be over 500 outages for a large TSP) would be in violation for excluding even one outage because of a naming problem that be corrected in 1 to 7 days in most cases. R5.1 requires the use of the Transmission Operator model, but NERC SDX outage data is based on a coordinated IDC model that is only updated for summer and winter. Some modeling can be different and therefore the names or bus numbers would not match creating a violation. Is there a consistent method that can be developed and incorporated into the requirements that helps guide TSPs to do the right thing without being severely penalized for temporary errors outside their control? Does NERC expect to interpret the effectiveness of this method?<br><br>PJM suggests eliminating the requirement or modifying it to state "as specified in the ATCID".<br><br>Response: In R1.2 the standard allows for each Transmission Service Provider to define, in their ATCID, how it handles outgaes. The Drafting Team expects that this would include the handling of unrecognized outages.<br><br><u>Requirement 6</u><br><br>• The "Medium" risk factor is inconsistent with NERC's definition of risk factors and should be changed to "Lower" if the requirement is to be retained.<br><br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br><br>• R6.1 PJM believes that including the impacts of base generation to load is a required component of the determination of ATC, but it should be separate from the ETC. The impacts of base generation to load is ambiguous, but the intent was to recognize that transmission and generation outages are applied to the base case model and solved. This changes the flows and AFC on the flowgates used for ATC calculation. These impacts are not really existing transmission commitments because they are not reservation or transmission service based. PJM believes that the language of the requirements and formula for calculating ATC should modified to clarify separate the base generation to load impacts from the ETC (transmission service) component and revise the formula as follows:<br><br>Response: The Drafting Team feels that for MOD-30 the base case generation to load impacts should be included in the ETC component. This allows for consistency in components that makeup the ATC/AFC formulas within all the methodologies. The Drafting Team did change "impact of base generation to load" to "impacts of generation to load in the model defined in 5.2" in order to clarify the language. |

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| | • R6.3 -PJM believes reservations in "Accepted", as well as, "Confirmed" status should be included. Once service is "Accepted" by a TSP it cannot be retracted. Not including "Accepted" reservation could result in overselling the transmission system and could lead to curtailments. Using reservations in Accepted and Confirmed status should also be included in MOD-001 R3.2.1<br>Response: The Drafting Team believes that the calculation of ETC should only include CONFIMRED reservations and rollover rights. Accepted reservations may be included in "Internal ATC," as described in FERC Order 638.<br><br>• R6.5, R6.6 and R7.3, R7.4 - PJM believes that requirements should specifically include that Grandfathered obligations can be included in the model. The phrase Grandfathered obligations that are not included in the model implies that some grandfathered obligations can be included in the model.<br>Response: The Drafting Team removed the language, "not included in the model". The intent of the standard is for the impacts to be accounted for and not double counted. Therefore the impact can be identified by either including the transactions in the model or by using the calculated distribution factor. In either case the impacts get summed up to make up the ETC component.<br><br>Requirement 8<br>• The medium risk factor is inconsistent with NERC's definition of risk factors and should be changed to lower if the requirement is to be retained.<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br><br>• R8 The formula should have a GTL variable representing the generation to load impacts that are currently lumped into ETC. to specifically<br>Response: The Drafting Team feels that for MOD-30 the base case generation to load impacts should be included in the ETC component. This allows for consistency in components that makeup the ATC/AFC formulas within all the methodologies. The Drafting Team did change "impact of base generation to load" to "impacts of generation to load in the model defined in 5.2" in order to clarify the language. |

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<tr><td></td><td><u>Requirement 9</u><br>• R9 Non-firm should be removed from this reliability standard and be considered NAESB scope.<br>Response: The SDT disagrees. Non-Firm is used in several other standards, and Non-Firm has the potential to have reliability impacts.<br><br><u>Requirement 10</u><br>PJM believes that the MOD standards go too far in areas that should be covered and addressed by Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices not in NERC standards as reliability based requirements (see specific details for MOD-001 R2 and R7 and MOD-030 R10 in Specific Comments sections below). Not recognizing the clear distinction between the reliability scope to be addressed by these standards and the NAESB business practices could cause inconsistencies in interpretation.<br>• The periodic requirements of R10 are NAESB scope. This requirement should be eliminated.<br>Response: The SDT disagrees, and believe there can be impacts on reliability if these calculations are not performed regularly.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Alabama Power Company</td><td>We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team.</td></tr>
<tr><td colspan="2">Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.</td></tr>
<tr><td>Bonneville Power Administration</td><td>BPA suggests a vote of No with the following comments:<br>The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make all of the necessary modifications to reflect the removal of the conversion requirement.<br>BPA suggests the following modifications be made to MOD-030-1:<br>o Change the following Requirements and Measures to replace each ATC with:<br>    o R1.2 - R1.2.2, R1.2.4, description of the first variable in R9, R10.3, and M17.<br>    o Change the Data Retention requirements in the second and fifth dashes to replace each TT with TF.<br>    o Change the Violation Severity Levels to replace Transfer Capabilities with AFC at R9 Severe VSL.<br>Response: These corrections have been made.<br><br>Additional barriers to an affirmative vote on MOD-030-1 are concerns about adding additional flowgates which would complicate operation with no benefit in reliability:<br>1. R2.1.1 and R2.1.2 do not take into consideration Special Protection Schemes (SPS) that are utilized within the Western Interconnection, which prevent some contingencies, which initiate use of a SPS, from being the limiting</td></tr>
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| | contingency. This can move the limiting contingencies outside the defined Flowgate, but does not require those contingencies to be in a Flowgate to reliably operate the transmission system. As written, additional contingency/limiting elements would need to be defined as Flowgates and unnecessary complexity will be added to operating the transmission system with no increased reliability benefit.<br>Response: R2.1.1.1 and R2.1.2.1 have been modified to include the use of SPS.<br><br>2. BPA has examples of transmission lines operated in series that would require separate Flowgates be defined for each transmission line as R2.1.1 and R2.1.2 are written because, at minimum, the first three limiting Element/contingency combinations are included as Flowgates. In our example, limiting for the most limiting Flowgate protects the others that are in series and should not require additional Flowgates be defined.<br>Response: The Drafting Team has inserted language to address this issue in 2.1.1.2 and 2.1.2.2<br><br>3. If Flowgates are defined based on protecting for multiple contingencies and outage conditions, the limiting element/contingency combinations can move away from the existing monitored Flowgates. Limiting the existing Flowgates can protect the transmission system without adding additional Flowgates.<br>Response: If a flowgate is defined to protect multiple contingencies and outage conditions, then the flowgate that needs to be defined is the most limiting monitored element/contingency pair. Therefore if the most limiting flowgate moves away from the existing monitored flowgate then a new flowgate should be defined.<br><br>4. This methodology seems to be more applicable to thermally limited Flowgates than voltage stability or transient stability. BPA has a Flowgate that can be limited by a generation loss and the limitation is reactive margin or voltage dip, rather than a specific element. The existing Flowgate is limited to protect for the generation loss. In this example the limiting contingency is not a Flowgate and the limiting element is not a Flowgate.<br>Response: R2.4 is intended to allow the specification of voltage or stability limited flowgates.<br><br>5. In R2.1.1 and R2.1.2 it is not clear what is meant by the first three limiting element/contingency combinations with an OTDF greater than 3% are included as Flowgates. Here are some possibilities: The limiting elements for the three most limiting contingencies need to be included as Flowgates. The three most limiting elements for the worst contingency need to be included as Flowgates. The three most limiting contingencies need to be included as Flowgates. The three most limiting contingencies and the most limiting elements for each contingency need to be included as Flowgates. An example would be helpful.<br>Response: The standard drafting team has added language to 2.1.1 and 2.1.2 to clarify what is meant by first three limiting element/contingency combinations.<br><br>BPA suggests these Requirements be rewritten in the following manner:<br>R2.1. Identify Flowgates used in the AFC process based, at a minimum, on the following criteria: |

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| | R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator system up to the path capability such that at a minimum the first three limiting Element/Contingency combinations with an OTDF greater than 3% and within the Transmission Operator system are included as Flowgates, or alternately SOLs and IROLs on a Transmission Operator system are included as Flowgates.<br>2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements/Contingency combinations with an Outage Transfer Distribution Factor (OTDF) greater than 3% and within the Transmission Operator system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology, or alternately SOLs and IROLs on a Transmission Operator system are included as Flowgates.<br>2.1.2.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.3. Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.<br>R2.1.4. Any credible limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:<br>2.1.4.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and<br>- Any generator within the Transmission Service Provider area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or<br>- A transfer from any Balancing Area within the Transmission Service Provider area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.<br>Response: The SDT has modified R2.1.1.1 and R2.1.2.1 to respond to the suggestions to acknowledge the use of SPS and has added a new R2.1.4.2 to further define a "credible" limiting Element/Contingency combinations that may be requested for inclusion. |
| Response: Please see in-line responses. | |
| Consolidated Edison Co. of New York | Some requirements (e.g. R2.1.1) stipulate that flowgates having a 3% OTDF are to be included for AFC calculation; whereas other requirements (e.g. R2.1.4.1) stipulate that flowgates with a 5% PTDF or OTDF are to be included. Despite this apparent inconsistency, after having these two sets of threshold stipulated and with requirements that link to the curtailment threshold (e.g. R6.2, R6.4 and R6.1), the standard makes provisions (e.g. 2.1.4.1, footnotes to R6.2, R6.4 and R6.6) that allow inclusion of flowgates at responses lower than these thresholds. The apparently conflicting requirements combined with the provisions to apply lower thresholds render the standard not measurable and enforceable. |

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<tr><th>Entity</th><th>Comment</th></tr>
<tr><td colspan="2">Response: The SDT has changed the sub-requirements under R2 to use a consistent 5%. The SDT intends for TOs to be able to use more conservative lower thresholds in both defining flowgates and including the impacts of adjacent reservations, if they so choose. The minimum thresholds were established to ensure the standards are measurable.</td></tr>
<tr><td>Dominion Resources, Inc.</td><td>In support of PJM and NPCC comments</td></tr>
<tr><td colspan="2">Response: Please see PJM and NPCC responses.</td></tr>
<tr><td>FirstEnergy Solutions</td><td>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br><br>CBM & TRM - MARKET AREAS: FE supports the drafting team approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc.<br><br>FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely as within both market and non-market areas as the PC and RC would be appropriate in both. Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br><br>Response: Please see responses contained in the CBM and TRM comment reports.<br><br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the Solicit Public Comments on Draft Standard (Step 6) of the NERC SDP is to Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus. Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br><br>Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.<br><br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:</td></tr>
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| | o Either the Planning Coordinator (PC) or Reliability Coordinator (RC) should replace the Transmission Operator (TOP) as having ultimate responsibility for the requirements in R2 and R3. The PC or RC will work with their associated Transmission Planners and/or TOPs to obtain the necessary information to properly identify flowgates and develop the proper transmission models.<br>Response: R2 & R3 will remain the responsibility of the Transmission Operator. The functions, responsibilities, and tasks of the Transmission Operator and Transmission Service Provider are defined in the NERC Reliability Functional Model. The Transmission Operator function ensures the real-time operating reliability of the transmission assets within a reliability area. The Drafting Team believes that the function of ensuring operating reliability includes identifying and maintaining flowgates per requirements R2 and developing the transmission models per requirement R3, and therefore is the Transmission Operator's responsibility.<br>o Also with regard to R2 and R3, we believe that there is too much detail in the subrequirements and that there may be other methods to identify flowgates and develop transmission models. These requirements should focus on the what and not the how.<br>Response: The Drafting Team believes that in order to maintain the reliability of the flowgate methodology, a minimum amount of flowgates need to be determined based on standard criteria. Please note that this is only used to determine the minimum amount of flowgates to be added, other processes can be used to add additional flowgates.<br>o The definitions for AFC and Flowgate Methodology should include mention of Postbacks and Counterflows which are significant factors in calculating AFC and ATC (see the algorithm of Requirement R8).<br>Response: The SDT has modified the definitions accordingly. |
| Response: Please see in-line responses. | |
| Georgia Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Gulf Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Hydro One Networks, Inc. | Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighbouring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td></td><td>modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained.<br><br>Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.<br><br>In addition we offer the following comments to the specific Standard MOD-030:<br>o Some requirements (e.g. R2.1.1) stipulate that flowgates having a 3% OTDF are to be included for AFC calculation; whereas other requirements (e.g. R2.1.4.1) stipulate that flowgates with a 5% PTDF or OTDF are to be included. Despite this apparent inconsistency, after having these two sets of threshold stipulated and with requirements that link to the curtailment threshold (e.g. R6.2, R6.4 and R6.1), the standard makes provisions (e.g. 2.1.4.1, footnotes to R6.2, R6.4 and R6.6) that allow inclusion of flowgates at responses lower than these thresholds. The apparently conflicting requirements combined with the provisions to apply lower thresholds render the standard not measurable and enforceable.<br><br>Response: The Drafting Team has changed the sub-requirements under R2 to use a consistent 5%. The SDT intends for TOs to be able to use more conservative lower thresholds in both defining flowgates and including the impacts of adjacent reservations, if they so choose. The minimum thresholds were established to ensure the standards are measurable.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Lincoln Electric System</td><td>LES supports BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period.</td></tr>
<tr><td colspan="2">Response: Please see responses to BPA, PJM, and MISO.</td></tr>
<tr><td>MidAmerican Energy Co.</td><td>I support the BPA position that further changes should be made to eliminate the TFC to TTC and AFC to ATC conversions. I also support the PJM recommendation that this standard needs another commenting period.</td></tr>
<tr><td colspan="2">Response: Please see BPA response.</td></tr>
<tr><td>Mississippi Power</td><td>We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team.</td></tr>
<tr><td colspan="2">Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.</td></tr>
<tr><td>New York Power Authority</td><td>MOD-030-1--recommendation to vote NO not accept. Some requirements (e.g. R2.1.1) stipulate that flowgates having a 3% OTDF are to be included for AFC calculation; whereas other requirements (e.g. R2.1.4.1) stipulate that flowgates with a 5% PTDF or OTDF are to be included. Despite this apparent inconsistency, after having these two sets of threshold stipulated and with requirements that link to the curtailment threshold (e.g. R6.2, R6.4 and R6.1), the standard makes provisions (e.g. 2.1.4.1, footnotes to R6.2, R6.4 and R6.6) that allow inclusion of flowgates at responses lower than these thresholds. The apparently conflicting requirements combined with the provisions to apply lower thresholds render the standard not measurable and enforceable.</td></tr>
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| Response: The SDT has changed the sub-requirements under R2 to use a consistent 5%. The SDT intends for TOs to be able to use more conservative lower thresholds in both defining flowgates and including the impacts of adjacent reservations, if they so choose. The minimum thresholds were established to ensure the standards are measurable. | |
| Public Service Electric and Gas Co. | PSE&G votes NO for the reasons expressed in PJM comments. |
| Response: Please see PJM response. | |
| Wisconsin Public Service Corp. | WPSC supports BPA position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: Please see responses to BPA, PJM, and MISO. | |
| Madison Gas and Electric Co. | We support BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period . |
| Response: Please see responses to BPA, PJM, and MISO. | |
| Bonneville Power Administration | The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC , but failed to make all of the necessary modifications to reflect the removal of the conversion requirement. BPA suggests the following modifications be made to MOD-030-1:<br>o Change the following Requirements and Measures to replace each ATC with AFC:<br>o R1.2 - R1.2.2, R1.2.4, description of the first variable in R9, R10.3, and M17.<br>o Change the Data Retention requirements in the second and fifth dashes to replace each TTC with TFC.<br>o Change the Violation Severity Levels to replace Transfer Capabilities with AFC at R9 Severe VSL.<br>Response: These corrections have been made.<br><br>Additional barriers to an affirmative vote on MOD-030-1 are concerns about adding additional flowgates which would complicate operation with no benefit in reliability:<br>1. R2.1.1 and R2.1.2 do not take into consideration Special Protection Schemes (SPS) that are utilized within the Western Interconnection, which prevent some contingencies, which initiate use of a SPS, from being the limiting contingency. This can move the limiting contingencies outside the defined Flowgate, but does not require those contingencies to be in a Flowgate to reliably operate the transmission system. As written, additional contingency/limiting elements would need to be defined as Flowgates and unnecessary complexity will be added to operating the transmission system with no increased reliability benefit.<br>Response: R2.1.1.1 and R2.1.2.1 have been modified to include the use of SPS. |

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| | 2. BPA has examples of transmission lines operated in series that would require separate Flowgates be defined for each transmission line as R2.1.1 and R2.1.2 are written because, at minimum, the first three limiting Element/contingency combinations are included as Flowgates. In our example, limiting for the most limiting Flowgate protects the others that are in series and should not require additional Flowgates be defined.<br>Response: The Drafting Team has inserted language to address this issue in 2.1.1.2 and 2.1.2.2<br><br>3. If Flowgates are defined based on protecting for multiple contingencies and outage conditions, the limiting element/contingency combinations can move away from the existing monitored Flowgates. Limiting the existing Flowgates can protect the transmission system without adding additional Flowgates.<br>Response: If a flowgate is defined to protect multiple contingencies and outage conditions, then the flowgate that needs to be defined is the most limiting monitored element/contingency pair.  Therefore if the most limiting flowgate moves away from the existing monitored flowgate then a new flowgate should be defined.<br><br>4. This methodology seems to be more applicable to thermally limited Flowgates than voltage stability or transient stability. BPA has a Flowgate that can be limited by a generation loss and the limitation is reactive margin or voltage dip, rather than a specific element. The existing Flowgate is limited to protect for the generation loss. In this example the limiting contingency is not a Flowgate and the limiting element is not a Flowgate.<br>Response: R2.4 is intended to allow the specification of voltage or stability limited flowgates.<br><br>5. In R2.1.1 and R2.1.2 it is not clear what is meant by the first three limiting element/contingency combinations with an OTDF greater than 3% are included as Flowgates. Here are some possibilities: The limiting elements for the three most limiting contingencies need to be included as Flowgates. The three most limiting elements for the worst contingency need to be included as Flowgates. The three most limiting contingencies need to be included as Flowgates. The three most limiting contingencies and the most limiting elements for each contingency need to be included as Flowgates. An example would be helpful.<br>Response: The standard drafting team has added language to 2.1.1 and 2.1.2 to clarify what is meant by first three limiting element/contingency combinations.<br><br>BPA suggests these Requirements be rewritten in the following manner:<br>R2.1. Identify Flowgates used in the AFC process based, at a minimum, on the following criteria:<br>R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator system up to the path capability such that at a minimum the first three limiting Element/Contingency combinations with an OTDF greater than 3% and within the Transmission Operator system are included as Flowgates, or alternately SOLs and IROLs on a Transmission Operator system are included as Flowgates.<br>2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods. |

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| | R2.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements/Contingency combinations with an Outage Transfer Distribution Factor (OTDF) greater than 3% and within the Transmission Operator system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology, or alternately SOLs and IROLs on a Transmission Operator system are included as Flowgates.<br>2.1.2.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.3. Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.<br>R2.1.4. Any credible limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:<br>2.1.4.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and<br>- Any generator within the Transmission Service Provider area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or<br>- A transfer from any Balancing Area within the Transmission Service Provider area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.<br>Response: The SDT has modified R2.1.1.1 and R2.1.2.1 to respond to the suggestions to acknowledge the use of SPS and has added a new R2.1.4.2 to further define a “credible” limiting Element/Contingency combinations that may be requested for inclusion. |
| Response: Please see in-line responses. | |
| Calpine Corporation | The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word transparency has been deleted from the purpose.<br>We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency. The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to the document. Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization. |

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| Response: NAESB is responsible for determining which information will be shared with market participants. While the standard does promote enhanced transparency, the purpose has been reworded to focus more on the reliability aspects of the standard. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation. | |
| Electric Power Supply Association | The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word transparency has been deleted from the purpose.<br>We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency. The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to the document. Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization.<br>In calculating the ATC or AFC as applicable, a significant factor in the calculations will be the assumed counterflows and postbacks. The standards provide no guidance on these terms, but rather leave them entirely to the discretion of the TSP, subject only to documentation of their assumptions in the ATCID, which might not be visible to market participants. |
| Response: NAESB is responsible for determining which information will be shared with market participants. While the standard does promote enhanced transparency, the purpose has been reworded to focus more on the reliability aspects of the standard. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation. | |
| FirstEnergy Solutions | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br>CBM & TRM - MARKET AREAS: FE supports the drafting team approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc.<br>FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely as within both market and non-market areas as the PC and RC would be appropriate in both. Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br>Response: Please see responses contained in the CBM and TRM comment reports. |

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| | DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the Solicit Public Comments on Draft Standard (Step 6) of the NERC SDP is to Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus. Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br>Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.<br><br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>– Either the Planning Coordinator (PC) or Reliability Coordinator (RC) should replace the Transmission Operator (TOP) as having ultimate responsibility for the requirements in R2 and R3. The PC or RC will work with their associated Transmission Planners and/or TOPs to obtain the necessary information to properly identify flowgates and develop the proper transmission models.<br>Response: R2 & R3 will remain the responsibility of the Transmission Operator. The functions, responsibilities, and tasks of the Transmission Operator and Transmission Service Provider are defined in the NERC Reliability Functional Model. The Transmission Operator function ensures the real-time operating reliability of the transmission assets within a reliability area. The Drafting Team believes that the function of ensuring operating reliability includes identifying and maintaining flowgates per requirements R2 and developing the transmission models per requirement R3, and therefore is the Transmission Operator's responsibility.<br><br>– Also with regard to R2 and R3, we believe that there is too much detail in the subrequirements and that there may be other methods to identify flowgates and develop transmission models. These requirements should focus on the what and not the how.<br>Response: The Drafting Team believes that in order to maintain the reliability of the flowgate methodology, a minimum amount of flowgates need to be determined based on standard criteria. Please note that this is only used to determine the minimum amount of flowgates to be added, other processes can be used to add additional flowgates.<br><br>– The definitions for AFC and Flowgate Methodology should include mention of Postbacks and Counterflows which are significant factors in calculating AFC and ATC (see the algorithm of Requirement R8). |

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| | Response: The SDT has modified the definitions accordingly. |
| Response: Please see in-line responses. | |
| Lincoln Electric System | LES supports BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: Please see BPA response. | |
| PPL Generation LLC | The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make all of the necessary modifications to reflect the removal of the conversion requirement. It is suggested that the following modifications be made to MOD-030-1:<br>– Change the following Requirements and Measures to replace each ATC with AFC:<br>– R1.2 - R1.2.2, R1.2.4, description of the first variable in R9, R10.3, and M17.<br>– Change the Data Retention requirements in the second and fifth dashes to replace each TTC with TFC.<br>– Change the Violation Severity Levels to replace Transfer Capabilities with AFC at R9 Severe VSL.<br>Response: These corrections have been made.<br><br>Additional barriers to an affirmative vote on MOD-030-1 are concerns about adding additional flowgates which would complicate operation with no benefit in reliability:<br>– R2.1.1 and R2.1.2 do not take into consideration Special Protection Schemes (SPS) that are utilized within the Western Interconnection, which prevent some contingencies, which initiate use of a SPS, from being the limiting contingency. This can move the limiting contingencies outside the defined Flowgate, but does not require those contingencies to be in a Flowgate to reliably operate the transmission system.<br>Response: R2.1.1.1 and R2.1.2.1 have been modified to include the use of SPS.<br><br>– As written, additional contingency/limiting elements would need to be defined as Flowgates and unnecessary complexity will be added to operating the transmission system with no increased reliability benefit. There are examples of transmission lines operated in series that would require separate Flowgates be defined for each transmission line as R2.1.1 and R2.1.2 are written because, at minimum, the first three limiting Element/contingency combinations are included as Flowgates. In our example, limiting for the most limiting Flowgate protects the others that are in series and should not require additional Flowgates be defined. If Flowgates are defined based on protecting for multiple contingencies and outage conditions, the limiting element/contingency combinations can move away from the existing monitored Flowgates. Limiting the existing Flowgates can protect the transmission system without adding additional Flowgates. This methodology seems to be more applicable to thermally limited Flowgates than voltage stability or transient stability. A Flowgate exists that can be limited by a generation loss and the limitation is reactive margin or voltage dip, rather than a specific element. The existing Flowgate is limited to protect for the generation loss. In this example the limiting contingency is not a Flowgate and the limiting element is not a Flowgate. |

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| | Response: If a flowgate is defined to protect multiple contingencies and outage conditions, then the flowgate that needs to be defined is the most limiting monitored element/contingency pair. Therefore if the most limiting flowgate moves away from the existing monitored flowgate then a new flowgate should be defined.<br><br>R2.4 is intended to allow the specification of voltage or stability limited flowgates.<br><br>– In R2.1.1 and R2.1.2 it is not clear what is meant by the first three limiting element/contingency combinations with an OTDF greater than 3% are included as Flowgates. Here are some possibilities: The limiting elements for the three most limiting contingencies need to be included as Flowgates. The three most limiting elements for the worst contingency need to be included as Flowgates. The three most limiting contingencies need to be included as Flowgates. The three most limiting contingencies and the most limiting elements for each contingency need to be included as Flowgates. An example would be helpful.<br>Response: The standard drafting team has added language to 2.1.1 and 2.1.2 to clarify what is meant by first three limiting element/contingency combinations.<br><br>It is suggested that these Requirements be rewritten in the following manner:<br>R2.1. Identify Flowgates used in the AFC process based, at a minimum, on the following criteria:<br>R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator system up to the path capability such that at a minimum the first three limiting Element/Contingency combinations with an OTDF greater than 3% and within the Transmission Operator system are included as Flowgates, or SOLs and IROLs on a Transmission Operator system are included as Flowgates..<br>2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements/Contingency combinations with an Outage Transfer Distribution Factor (OTDF) greater than 3% and within the Transmission Operator system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology or SOLs and IROLs on a Transmission Operator system are included as Flowgates.<br>2.1.2.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.3. Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.<br>R2.1.4. Any credible limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where: |

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| | 2.1.4.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and - Any generator within the Transmission Service Provider area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or - A transfer from any Balancing Area within the Transmission Service Provider area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.<br>Response: The SDT has modified R2.1.1.1 and R2.1.2.1 to respond to the suggestions to acknowledge the use of SPS and has added a new R2.1.4.2 to further define a "credible" limiting Element/Contingency combinations that may be requested for inclusion. |
| Response: Please see in-line responses. | |
| PSEG Power LLC | PSEG Power LLC votes no for the reasons expressed in PJM comments. |
| Response: Please see PJM response. | |
| Barry Green Consulting Inc. | Transparency: The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the standard that is being balloted, the word transparency has been deleted from the purpose.<br>We also note that a requirement that sufficient data be exchanged to allow for validation of the ATC calculation is included but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency. The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to the document.<br>Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization.<br>In calculating the ATC or AFC as applicable, a significant factor in the calculations will be the assumed counterflows and postbacks. The standards provide no guidance on these terms, but rather leave them entirely to the discretion of the TSP, subject only to documentation of their assumptions in the ATCID. We would be concerned if these values are unduly conservative. |
| Response: NAESB is responsible for determining which information will be shared with market participants. While the standard does promote enhanced transparency, the purpose has been reworded to focus more on the reliability aspects of the standard. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation. | |
| Bonneville Power | The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make all of the necessary modifications to reflect the removal of the conversion requirement. BPA suggests the following |

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| Administration | modifications be made to MOD-030-1:<br>o Change the following Requirements and Measures to replace each ATC with AFC:<br>    o R1.2 - R1.2.2, R1.2.4, description of the first variable in R9, R10.3, and M17.<br>    o Change the Data Retention requirements in the second and fifth dashes to replace each TTC with TFC.<br>    o Change the Violation Severity Levels to replace Transfer Capabilities with AFC at R9 Severe VSL.<br>Response: These corrections have been made.<br><br>Additional barriers to an affirmative vote on MOD-030-1 are concerns about adding additional flowgates, which would complicate operation with no benefit in reliability:<br>1. R2.1.1 and R2.1.2 do not take into consideration Special Protection Schemes (SPS) that are utilized within the Western Interconnection, which prevent some contingencies, which initiate use of a SPS, from being the limiting contingency. This can move the limiting contingencies outside the defined Flowgate, but does not require those contingencies to be in a Flowgate to reliably operate the transmission system. As written, additional contingency/limiting elements would need to be defined as Flowgates and unnecessary complexity will be added to operating the transmission system with no increased reliability benefit.<br>Response: R2.1.1.1 and R2.1.2.1 have been modified to include the use of SPS.<br><br>2. BPA has examples of transmission lines operated in series that would require separate Flowgates be defined for each transmission line as R2.1.1 and R2.1.2 are written because, at minimum, the first three limiting Element/contingency combinations are included as Flowgates. In our example, limiting for the most limiting Flowgate protects the others that are in series and should not require additional Flowgates be defined.<br>Response: The Drafting Team has inserted language to address this issue in 2.1.1.2 and 2.1.2.2<br><br>3. If Flowgates are defined based on protecting for multiple contingencies and outage conditions, the limiting element/contingency combinations can move away from the existing monitored Flowgates. Limiting the existing Flowgates can protect the transmission system without adding additional Flowgates.<br>Response: If a flowgate is defined to protect multiple contingencies and outage conditions, then the flowgate that needs to be defined is the most limiting monitored element/contingency pair. Therefore if the most limiting flowgate moves away from the existing monitored flowgate then a new flowgate should be defined.<br><br>4. This methodology seems to be more applicable to thermally limited Flowgates than voltage stability or transient stability. BPA has a Flowgate that can be limited by a generation loss and the limitation is reactive margin or voltage dip, rather than a specific element. The existing Flowgate is limited to protect for the generation loss. In this example the limiting contingency is not a Flowgate and the limiting element is not a Flowgate.<br>Response: R2.4 is intended to allow the specification of voltage or stability limited flowgates. |

| Entity | Comment |
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| | 5. In R2.1.1 and R2.1.2 it is not clear what is meant by the first three limiting element/contingency combinations with an OTDF greater than 3% are included as Flowgates. Here are some possibilities: The limiting elements for the three most limiting contingencies need to be included as Flowgates. The three most limiting elements for the worst contingency need to be included as Flowgates. The three most limiting contingencies need to be included as Flowgates. The three most limiting contingencies and the most limiting elements for each contingency need to be included as Flowgates. An example would be helpful.<br>Response: The standard drafting team has added language to 2.1.1 and 2.1.2 to clarify what is meant by first three limiting element/contingency combinations.<br><br>BPA suggests these Requirements be rewritten in the following manner:<br>R2.1. Identify Flowgates used in the AFC process based, at a minimum, on the following criteria:<br>R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator system up to the path capability such that at a minimum the first three limiting Element/Contingency combinations with an OTDF greater than 3% and within the Transmission Operator system are included as Flowgates, or alternately SOLs and IROLs on a Transmission Operator system are included as Flowgates.<br>2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements/Contingency combinations with an Outage Transfer Distribution Factor (OTDF) greater than 3% and within the Transmission Operator system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology, or alternately SOLs and IROLs on a Transmission Operator system are included as Flowgates.<br>2.1.2.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.3. Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.<br>R2.1.4. Any credible limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:<br>2.1.4.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and<br>- Any generator within the Transmission Service Provider area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or |

<table>
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<tr><td></td><td>- A transfer from any Balancing Area within the Transmission Service Provider area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.<br>Response: The SDT has modified R2.1.1.1 and R2.1.2.1 to respond to the suggestions to acknowledge the use of SPS and has added a new R2.1.4.2 to further define a “credible” limiting Element/Contingency combinations that may be requested for inclusion.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Consolidated Edison Co. of New York</td><td>Some requirements(eg.R2.1.1) stipulate that flowgates having a 3% OTDF are to be included for AFC calculation; whereas other requirements(e.g. R2.1.4.1) stipulate that flowgates with a 5% PTDF or OTDF are to be included. Despite this apparent inconsistency, after having these two sets of threshold stipulated and with requirements that link to the curtailment threshold (e.g. R6.2, R6.4, and R6.1), the standard makes provisions(eg.2.1.4.1, footnotes to R6.2,R6.4 and R6.6) that allow inclusion of flowgates at responses lower than these thresholds. The apparently conflicting requirements combined with the provisions to apply lower thresholds render the standard not measureable and enforceable.</td></tr>
<tr><td colspan="2">Response: The SDT has changed the sub-requirements under R2 to use a consistent 5%. The SDT intends for TOs to be able to use more conservative lower thresholds in both defining flowgates and including the impacts of adjacent reservations, if they so choose. The minimum thresholds were established to ensure the standards are measurable.</td></tr>
<tr><td>Dominion Resources, Inc.</td><td>Support comments provided by NPCC and PJM</td></tr>
<tr><td colspan="2">Response: Please see NPCC and PJM responses.</td></tr>
<tr><td>FirstEnergy Solutions</td><td>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>o Either the Planning Coordinator (PC) or Reliability Coordinator (RC) should replace the Transmission Operator (TOP) as having ultimate responsibility for the requirements in R2 and R3. The PC or RC will work with their associated Transmission Planners and/or TOPs to obtain the necessary information to properly identify flowgates and develop the proper transmission models.<br>Response: R2 & R3 will remain the responsibility of the Transmission Operator. The functions, responsibilities, and tasks of the Transmission Operator and Transmission Service Provider are defined in the NERC Reliability Functional Model. The Transmission Operator function ensures the real-time operating reliability of the transmission assets within a reliability area. The Drafting Team believes that the function of ensuring operating reliability includes identifying and maintaining flowgates per requirements R2 and developing the transmission models per requirement R3, and therefore is the Transmission Operator’s responsibility.<br>o Also with regard to R2 and R3, we believe that there is too much detail in the subrequirements and that there may be other methods to identify flowgates and develop transmission models. These requirements should focus on the what and not the how.<br>Response: The Drafting Team believes that in order to maintain the reliability of the flowgate methodology, a minimum</td></tr>
</table>

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<tr><th>Entity</th><th>Comment</th></tr>
<tr><td></td><td>amount of flowgates need to be determined based on standard criteria. Please note that this is only used to determine the minimum amount of flowgates to be added, other processes can be used to add additional flowgates.<br><br>o The definitions for AFC and Flowgate Methodology should include mention of Postbacks and Counterflows which are significant factors in calculating AFC and ATC (see the algorithm of Requirement R8).<br>Response: The SDT has modified the definitions accordingly.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Lincoln Electric System</td><td>LES supports BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period.</td></tr>
<tr><td colspan="2">Response: Please see responses to BPA, PJM, and MISO.</td></tr>
<tr><td>MidAmerican Energy Co.</td><td>Although this standard leaves much to be desired, it is better than the current standard. I hope NERC continues to work towards consistency in the arena of transfer capability.</td></tr>
<tr><td colspan="2">Response: Thank you.</td></tr>
<tr><td>PP&L, Inc.</td><td>The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make all of the necessary modifications to reflect the removal of the conversion requirement. It is suggested that the following modifications be made to MOD-030-1:<br>– Change the following Requirements and Measures to replace each ATC with AFC:<br>o R1.2 - R1.2.2, R1.2.4, description of the first variable in R9, R10.3, and M17.<br>o Change the Data Retention requirements in the second and fifth dashes to replace each TT with TF.<br>o Change the Violation Severity Levels to replace Transfer Capabilities with AFC at R9 Severe VSL.<br>Response: These corrections have been made.<br><br>Additional barriers to an affirmative vote on MOD-030-1 are concerns about adding additional flowgates, which would complicate operation with no benefit in reliability:<br>o R2.1.1 and R2.1.2 do not take into consideration Special Protection Schemes (SPS) that are utilized within the Western Interconnection, which prevent some contingencies, which initiate use of a SPS, from being the limiting contingency. This can move the limiting contingencies outside the defined Flowgate, but does not require those contingencies to be in a Flowgate to reliably operate the transmission system.<br>Response: R2.1.1.1 and R2.1.2.1 have been modified to include the use of SPS.<br><br>o As written, additional contingency/limiting elements would need to be defined as Flowgates and unnecessary complexity will be added to operating the transmission system with no increased reliability benefit. There are examples of transmission lines operated in series that would require separate Flowgates be defined for each</td></tr>
</table>

| Entity | Comment |
| --- | --- |
| | transmission line as R2.1.1 and R2.1.2 are written because, at minimum, the first three limiting Element/contingency combinations are included as Flowgates. In our example, limiting for the most limiting Flowgate protects the others that are in series and should not require additional Flowgates be defined. If Flowgates are defined based on protecting for multiple contingencies and outage conditions, the limiting element/contingency combinations can move away from the existing monitored Flowgates. Limiting the existing Flowgates can protect the transmission system without adding additional Flowgates. This methodology seems to be more applicable to thermally limited Flowgates than voltage stability or transient stability. A Flowgate exists that can be limited by a generation loss and the limitation is reactive margin or voltage dip, rather than a specific element. The existing Flowgate is limited to protect for the generation loss. In this example the limiting contingency is not a Flowgate and the limiting element is not a Flowgate.<br>Response: If a flowgate is defined to protect multiple contingencies and outage conditions, then the flowgate that needs to be defined is the most limiting monitored element/contingency pair. Therefore if the most limiting flowgate moves away from the existing monitored flowgate then a new flowgate should be defined.<br><br>R2.4 is intended to allow the specification of voltage or stability limited flowgates<br><br>o In R2.1.1 and R2.1.2 it is not clear what is meant by the first three limiting element/contingency combinations with an OTDF greater than 3% are included as Flowgates. Here are some possibilities: The limiting elements for the three most limiting contingencies need to be included as Flowgates. The three most limiting elements for the worst contingency need to be included as Flowgates. The three most limiting contingencies need to be included as Flowgates. The three most limiting contingencies and the most limiting elements for each contingency need to be included as Flowgates. An example would be helpful.<br>Response: The standard drafting team has added language to 2.1.1 and 2.1.2 to clarify what is meant by first three limiting element/contingency combinations.<br><br>It is suggested that these Requirements be rewritten in the following manner:<br>R2.1. Identify Flowgates used in the AFC process based, at a minimum, on the following criteria:<br>R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator system up to the path capability such that at a minimum the first three limiting Element/Contingency combinations with an OTDF greater than 3% and within the Transmission Operator system are included as Flowgates, or SOLs and IROLs on a Transmission Operator system are included as Flowgates..<br>2.1.1.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements/Contingency combinations with an Outage Transfer Distribution Factor (OTDF) greater than 3% and within the Transmission Operator system are included as Flowgates unless the interface |

| Entity | Comment |
|---|---|
| | between such adjacent Balancing Authorities is accounted for using another ATC methodology or SOLs and IROLs on a Transmission Operator system are included as Flowgates.<br>2.1.2.1. Use Contingency assumptions consistent with those used in operations studies and planning studies for the applicable time periods.<br>R2.1.3. Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.<br>R2.1.4. Any credible limiting element/contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:<br>2.1.4.1. If the coordination of the limiting element/contingency combination is not already addressed through a different methodology, and - Any generator within the Transmission Service Provider area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or - A transfer from any Balancing Area within the Transmission Service Provider area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.<br>Response: The SDT has modified R2.1.1.1 and R2.1.2.1 to respond to the suggestions to acknowledge the use of SPS and has added a new R2.1.4.2 to further define a “credible” limiting Element/Contingency combinations that may be requested for inclusion. |
| Response: Please see in-line responses. | |
| PSEG Energy Resources & Trade LLC | PSEG Energy Resources & Trade LLC votes NO for the reasons expressed in PJM's ballot. |
| Response: Please see PJM response. | |
| Commonwealth of Massachusetts Department of Public Utilities | Due to the extensive revisions in the final draft, industry input should have been solicited before setting this revised standard for a vote. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| National Association of Regulatory Utility Commissioners | Due to the extensive revisions in the final draft, industry input should have been solicited before setting this revised standard for a vote. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |

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<tr><td>Midwest Reliability Organization</td><td>The MRO supports BPA position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period.</td></tr>
<tr><td colspan="2">Response:  Please see responses to BPA, PJM, and MISO.</td></tr>
<tr><td>Northeast Power Coordinating Council, Inc.</td><td>The variability of distribution factor thresholds will make enforceability of some requirements problematic.</td></tr>
<tr><td colspan="2">Response: The SDT has changed the sub-requirements under R2 to use a consistent 5%.  The SDT intends for Transmission Operators to be able to use more conservative lower thresholds in both defining flowgates and including the impacts of adjacent reservations, if they so choose.  The minimum thresholds were established to ensure the standards are measurable.</td></tr>
</table>

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted second first for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30 Day posting before board adoption. | March 7, 2008 |
| 5. Board adopts MOD-001-1. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Rated System Path Methodology:** The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

## A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

**R1.1.1.** Includes at least:

1.1.1.1. The Transmission Operator area.

1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area.

1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement.

**R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.

**R1.1.3.** Models all generation Facilities larger than 20 MVA in the studied area.

**R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the ATCID.

**R1.1.5.** Uses Load forecast by Balancing Authority.

**R1.1.6.** Uses Transmission Facility additions and retirements.

**R1.1.7.** Uses Generation Facility additions and retirements.

**R1.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

**R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

**R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

**R2.** The Transmission Operator shall use the following process to determine TTC: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

**R2.1.1.** When modeling normal conditions, do not model any Transmission Element above 100% of its continuous rating.

**R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

**R2.1.3.** Uncontrolled separation shall not occur.

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction.

**R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

**R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** Verify that the TTC for the ATC Path being studied does not adversely impact the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

**R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

$\mathbf{NL_F}$ is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$\mathbf{ROR_F}$ is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_{NF}$** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + Counterflows_F$$

**Where**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm Available Transfer Capability due to a change in the use of Firm Transmission Service for that period, as defined in Business Practices.

**$Counterflows_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

**R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$ATC_{NF} = TTC – ETC_F – ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + Counterflows_{NF}$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Transfer Capability due to a change in the use of Non-Firm Transmission Service for that period, as defined in Business Practices.

**$Counterflows_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC used in its ATC calculations, as required in R1. (R1)

**M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (R1.1)

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

**M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

**M7.** Each Transmission Service Provider shall produce the algorithms it used to calculate ETCs for Firm and Non-Firm Transmission Service, as required in R5 and R6, showing that only the variables allowed in R5 and R6 were used to calculate ETCs. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R5 and R6)

**M7.1.** Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ETCs in R5 and R6. (R5 and R6)

**M8.** Each Transmission Service Provider shall produce the algorithms it used to calculate firm and non-firm ATCs, as required in R7 and R8, showing that only the variables allowed in R7 and R8 were used to calculate ATCs. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R7 and R8)

**M8.1.** Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ATCs in R7 and R8. (R7 and R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R5, R6, R7 and R8. (M7 and M8)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator met all but one of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator met all but two of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator met all but three of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator did not meet four or more of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. |
| R2 | N/A | N/A | N/A | The Transmission Operator did not calculate TTC using the process described in R2. |
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 1 ATC Path OR more than 0% but less than 1% of all ATC Paths | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 2 ATC Paths OR 1% or more but less than 2% of all ATC Paths. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 3 ATC Paths OR 2% or more but less than 5% of all ATC Paths. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in or any associated SOL, for the larger of 4 or more ATC Paths OR 5% or more of all ATC Paths. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider 28 or more calendar days after the report was finalized. |
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R5 when determining firm ETC, or used additional elements. |
| R6. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R6 when determining non-firm ETC, or used additional elements. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements. |
| R8. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted second first for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30 Day posting before board adoption. | March 7, 2008 |
| 5. Board adopts MOD-001-1. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Rated System Path Methodology:** The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC to derive Available ~~Transmission~~ Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

## A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-1**

3. **Purpose:** To increase consistency and reliability~~transparency~~ in the development and documentation of transfer capability calculations for short-term use ~~Transmission services~~ performed by entities using the Rated System Path Methodology to support analysis and~~reliable~~ system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths~~Posted Paths~~.

   **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths~~Posted Paths~~.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that ~~all six (~~MOD-001-1, ~~MOD-004-1, MOD-008-1,~~ MOD-028-1, MOD-029-1, and MOD-030-1~~)ATC-related standards~~ are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** When calculating TTCs for ATC Paths~~Posted Paths~~, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria: ~~[*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]~~

**~~R1.1.~~R1.1.1.** Includes at least:

~~R1.1.1.~~1.1.1.1. The Transmission Operator ~~Area~~area.

~~R1.1.2.~~1.1.1.2. All Transmission Operator ~~Areas~~ areas contiguous with its own Transmission Operator ~~Area~~ area.

~~R1.1.3.~~1.1.1.3. Any other Transmission Operator ~~Area~~ area linked to the Transmission Operator's ~~Area~~ area by joint operating agreement.

**~~R1.2.~~R1.1.2.** Models all system ~~elements~~ Elements as in-service for the assumed initial conditions.

**~~R1.3.~~R1.1.3.** Models all generation Facilities larger than 20 MVA in the studied area.

**~~R1.4.~~R1.1.4.** Models phase shifters in ~~Non~~non-regulating mode, unless otherwise specified in the ATCID.

~~**R1.1.5.**Uses current Facility Ratings as provided by the Transmission Owner and Generator Owner~~

**~~R1.6.~~R1.1.5.** Uses ~~peak l~~Load forecast by Balancing Authority.

**~~R1.7.~~R1.1.6.** Uses Transmission Facility additions and retirements.

**~~R1.8.~~R1.1.7.** Uses Generation Facility additions and retirements.

~~**R1.9.**~~**R1.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

~~**R1.10.**~~**R1.1.9.** Models series compensation for each ~~"Extra High Voltage (EHV)"~~ line at the expected operating level unless specified otherwise in the ATCID.

~~**R1.11.**~~**R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

~~**R1.1.12.** Where three phase fault damping is used to determine stability limits, identifies the percent used and includes justification for use unless specified otherwise in the ACTID.~~

~~Each of the entities identified in R1.1.1 have reviewed and accepted the model as accurately representing their system.~~

**R2.** The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or ~~(~~reliability limit) that can be simulated on the ATC Path ~~Posted Path~~ while at the same time satisfying all planning criteria ~~for N-0, N-1, and N-2~~ contingencies as follows:

**R2.1.1.** When modeling normal conditions ~~(N-0)~~, do not model any Transmission Element above 100% of its continuous rating.

**R2.1.2.** When modeling ~~N-1 or N-2~~ contingencies~~,~~ the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its ~~emergency~~ Emergency ~~rating~~Rating.

~~**R2.1.3.** Do not exceed any Facility Ratings (including thermal and voltage ratings)~~

~~**R2.1.4.**~~**R2.1.3.** Uncontrolled separation shall not occur.

~~**R2.1.5.** Initiate system disturbances for stability studies by a three-phase-to-ground fault on all modeled "Extra High Voltage (EHV)" buses adjacent to the major interconnection point of the modeled Posted Path.~~

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current ~~transmission~~ Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction.

**R2.3.** For an ATC Path ~~Posted Path~~ whose capacity is limited by contract, set TTC on the ATC Path ~~Posted Path~~ at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R~~1.~~2.1.

**R2.4.** For an ATC Paths~~Posted Paths~~ whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** Verify that the TTC for the ~~Posted Path~~ATC Path being studied does not adversely impact the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path,~~Posted Path,~~ allocate TTC of that ATC Path~~Posted Path~~ in accordance with the contractual agreement made by the multiple owners of that ATC Path~~Posted Path~~.

**R2.7.** For ATC Paths ~~Posted Paths~~ whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken~~and the Regional Entity has not taken action~~ to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**~~R3.~~R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path~~Posted Path~~, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path~~Posted Path~~.

~~**R4.**Each Transmission Operator shall establish the TTC at the lesser of the TTC calculated in MOD-029-1 or any System Operating Limit for that Posted Path. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]~~

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for an ATC Path~~a Posted Path~~, the Transmission Service Provider shall use the ~~following~~ algorithm below: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

$\mathbf{NL_F}$ is the firm capacity set aside ~~reserved~~ to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth,~~ and losses~~ not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and ~~load~~ Load growth, ~~and losses~~ not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the firm capacity set aside ~~reserved~~ for grandfathered ~~Firm~~ Transmission Service and ~~bundled~~ contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service~~,~~.

**ROR$_F$** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**OS$_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC$_{NF}$) for all time horizons for an ATC Path ~~a Posted Path~~ the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**NITS$_{NF}$** is the non-firm capacity set aside ~~reserved~~ for Network Integration Transmission Service serving Load (i.e., ~~S~~secondary s~~S~~ervice), ~~,~~ to include losses, and load growth~~, and losses~~ not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF$_{NF}$** is the non-firm capacity set aside ~~reserved~~ for grandfathered Transmission Service and ~~bundled~~ contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**PTP$_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**OS$_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**R7.** When calculating f~~F~~irm ATC for an ATC Path ~~a Posted Path~~ for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + Counter\text{-}\cancel{schedule}flows_F$$

**Where**

**ATC$_F$** is the firm Available Transfer Capability for the ATC Path ~~Posted Path~~ for that period.

**TTC** is the Total Transfer Capability of the ATC Path ~~Posted Path~~ for that period.

**ETC$_F$** is the sum of existing firm commitments for the ATC Path ~~Posted Path~~ during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path ~~Posted Path~~ during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path ~~Posted Path~~ during that period.

**Postbacks$_F$** are ~~adjustments~~ changes to firm Available Transfer Capability due to a change in the use of Firm Transmission Service~~postbacks~~ for that period, as defined in ~~business~~ Business P~~p~~ractices.

**Counter~~-schedules$_F$~~ flows$_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and ~~described~~ specified in their ~~Available Transfer Capability Implementation Document.~~ ATCID.

**R8.** When calculating non-firm ATC for an ATC Path ~~Posted Path~~ for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$ATC_{NF} = TTC – ETC_{F} – ETC_{NF} – CBM_{S} – TRM_{U} + Postbacks_{NF} + Counter$flows ~~schedules~~$_{NF}$

**Where:**

**ATC$_{NF}$** is the non-firm Available Transfer Capability for the ATC Path ~~Posted Path~~ for that period.

**TTC** is the Total Transfer Capability of the ATC Path ~~Posted Path~~ for that period.

**ETC$_{F}$** is the sum of existing ~~non-~~firm commitments for the ATC Path ~~Posted Path~~ during that period.

**ETC$_{NF}$** is the sum of existing non-firm commitments for the ATC Path ~~Posted Path~~ during that period.

**CBM$_{S}$** is the Capacity Benefit Margin for the ATC Path ~~Posted Path~~ that has been scheduled during that period.

**TRM$_{U}$** is the Transmission Reliability Margin for the ATC Path ~~Posted Path~~ that has not been released for sale -(unreleased) as non-firm capacity by the Transmission Service Provider during that period~~,~~.

**Postbacks$_{NF}$** are ~~adjustments~~ changes to non-firm Available Transfer Capability due to a change in the use of Non-Firm Transmission Service~~postbacks~~ for that period, as defined in B~~b~~usiness P~~p~~ractices~~, and~~.

**Counter** ~~sche~~**flows**~~dules~~$_{NF}$ are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and ~~described~~ specified in its ~~Available Transfer Capability Implementation Document.~~ATCID.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any~~each~~ Transmission model it used to calculate TTC for purposes of -calculating ~~posting~~ ATC for each ATC Path~~Posted Path~~, as required in R1, for the time horizon(s) to be examined. (R1)

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC used in its ~~posted~~ATC calculations, as required in R1. (R1)

~~M1.2.~~The Transmission model produced must include the areas listed ~~show the use of each attribute specified~~ in R1.1.1 (R1.1)~~; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred.~~

**M1.2.**

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.~~1~~1~~10~~2; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

~~M1.3.~~**M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)~~the entities identified in R1.1.1 have reviewed the~~

~~model and agree with the accuracy of the representation of their system. Entities that have elected to not review the model shall be assumed to have~~

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (~~See~~ R1.1.4, R.1.1.~~10~~9, and R1.1.10~~1 and R1.12~~).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. -(R2.7)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

~~**M3.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the source documents reflecting the values it used to meet the requirements in R1.1.5 through R1.1.9 for the period examined. (R1)~~

~~**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the models, reports, or study results that it used to establish TTC in accordance with R2.1 through R2.78. (R2)~~

~~**M5.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)~~

~~Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)~~

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (~~R3~~R4)

~~**M7.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R.1.2 for each ATC PathPosted Path, 2) Any corresponding SOLs for those ATC PathPosted Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R6 R7and R7 R8 for each ATC PathPosted Path. (R4)~~

**M7.** Each Transmission Service Provider shall produce the algorithms it used to calculate ETCs for Firm and Non-Firm Transmission Service, as required in R5 and R6, showing that only the variables allowed in R5 and R6 were used to calculate ETCs. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R5 and R6)

~~M8.~~

**~~M8.1.~~M7.1.** Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ETCs in R5 and R6. (R5 and R6)

**~~M9.~~M8.** Each Transmission Service Provider shall produce the algorithms it used to calculate f~~F~~irm and n~~N~~on-f~~F~~irm ATCs, as required in R7 and R8, showing that only the variables allowed in R7 and R8 were used to calculate ATCs. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R7 and R8)

~~M9.1.~~M8.1. Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ATCs in R7 and R8. (R7 and R8)

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Data Retention**

- The Transmission Operator shall have its latest models used to determine TTC ~~and evidence of previous versions~~ for R1. (M1 ~~and M6~~)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- ~~The Transmission Operator shall retain the latest version and the prior version of the source documents used to update its models to show compliance with R1. (M3)~~
- ~~The Transmission Operator shall retain evidence to show compliance with R2.1 through R2.7~~ 8 ~~for the most recent three calendar years plus the current year. (M4)~~
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (~~M5~~M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with ~~R1,~~ R3 and R4. (~~M6~~ M5 and ~~M7~~M6)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R5, R6, R7 and R8. (~~M8~~ M7 and ~~M9~~M8)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits

- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator met all but one of the modeling requirements specified in R1.1<br>~~**OR**~~<br>~~The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and one of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths~~.<br>**OR**<br>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator met all but two of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~**OR**~~<br>~~The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and two to five of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths.~~ | The Transmission Operator met all but three of the modeling requirements specified in R1.1.<br>**OR**<br>~~**OR**~~<br>~~The Transmission Operator failed to demonstrate that one of the affected parties identified in R1.1.1 .~~The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~ and six to ten of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths.~~ | The Transmission Operator did not meet four or more of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~**OR**~~<br>~~The Transmission Operator failed to demonstrate that two or more of the affected parties identified in R1.1.1 The Transmission Operator utilized Facility Ratings that were different from those specified by a Transmission Owner in their Transmission model and eleven or more of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted Paths.~~ |
| R2 | N/A | N/A | N/A | The Transmission Operator did not calculate TTC using the |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | process described in R2. |
| ~~R3.~~<br>~~R4~~R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 1 ATC Path OR more than 0% but less than 1% of all ATC Paths ~~The Transmission Operator provided the TTC and study report to the Transmission Service Provider after more than seven, but not more than 14 calendar days after the report was finalized.~~<br>~~N/A~~ | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 2 ATC Paths OR 1% or more but less than 2% of all ATC Paths.~~The Transmission Operator provided the TTC and study report to the Transmission Service Provider after more than 14, but not more than 21 calendar days after the report was finalized.~~<br>~~N/A~~ | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated SOL for the larger of 3 ATC Paths OR 2% or more but less than 5% of all ATC Paths.~~The Transmission Operator provided the TTC and study report to the Transmission Service Provider after more than 21, but not more than 28 calendar days after the report was finalized.~~<br>~~The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R4 or any associated the SOL for one to four Posted PathsATC Paths.~~ | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in or any associated SOL, for the larger of 4 or more ATC Paths OR 5% or more of all ATC Paths. ~~The Transmission Operator provided the TTC and study report to the Transmission Service Provider 28 or more calendar days after the report was finalized.~~<br>~~The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in or any associated the SOL, for five or more Posted PathsATC Paths.~~ |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider 28 or more calendar days after the report was finalized. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R5 when determining ~~F~~firm ETC, or used additional elements. |
| R6. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R6 when determining ~~N~~non-~~F~~firm ETC, or used additional elements. |
| R7. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R7 when determining ~~F~~firm ATC, or used additional elements. |
| R8. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R8 when determining ~~N~~non-~~F~~firm ATC, or used additional elements. |

# Implementation Plan for Standard MOD-029-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-029-1, which describes the Rated System Path methodology for determining ATC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard incorporates the following requirements from FAC-012-1:

– R1 (Documentation of the Transfer Capability Methodology)

– R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

– R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013-1:

– R1 (Calculation of the Transfer Capabilities)

– R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-029-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

## Summary Consideration of Comments:

The Drafting Team has reviewed the comments and made some changes to the standard to address these comments.

1. All VRFs were set to "Lower" in response to industry comments. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
2. A more graded approach was applied to the VSLs where appropriate.
3. During the review of the VSLs and Measures, it was determined that the measures for R5, R6, R7, and R8 did not adequately measure compliance with the requirements. The drafting team updated the measures and VSLs to ensure that they captured the need to have accurate and valid numbers used in the requirements.
4. R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS).
5. MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/standards/newstandardsprocess.html.

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td>Bonneville Power Administration</td><td>R2.2 Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction maximum flow that can be simulated. The justification for this wording change stems from system reliability concerns surrounding "future" electrical system changes that would enable a higher transfer on a system that, prior to the system change, could not achieve this flow. A higher TTC would be allowed after the system reliability considerations at the higher TTC have been satisfied.</td></tr>
<tr><td colspan="2">Response: MOD-029 R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS). In that case the TTC in the non-prevailing direction will be limited to the greater of the flow that can be simulated in the non-prevailing direction or the TTC that can be achieved in the prevailing flow direction without the use of the SPS.</td></tr>
<tr><td>CenterPoint Energy</td><td>ERCOT's filed comments to the SDT that ATC, TTC, CBM, and TRM are not applicable within ERCOT operations and that these Standards should have provisions that make it clear that these requirements apply only within market structures in which they are pertinent were ignored by the SDT. These standards should not apply to ERCOT, thus our negative vote.</td></tr>
<tr><td colspan="2">Response: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any path for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT, and would not require implementation of any methodology, including this standard.</td></tr>
<tr><td>Consolidated Edison Co. of New York</td><td>R1.1.1.2 should allow for the use of equivalents (in lieu of detailed modeling of neighboring areas).</td></tr>
<tr><td colspan="2">Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.</td></tr>
<tr><td>Great River Energy</td><td>GRE does not believe that this standard applies in our region.</td></tr>
<tr><td colspan="2">Response: No response required.</td></tr>
<tr><td>Hydro One Networks, Inc.</td><td>Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighbouring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained.</td></tr>
</table>

| Entity | Comment |
|---|---|
| | In addition we offer the following comments to the specific Standard MOD-029: As drafted, the Standard does not permit any equivalent modeling of neighbouring areas (which is permitted in MOD-028-1). |
| Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.<br><br>MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| Hydro-Quebec TransEnergie | Requirement 1.1.1.2 asks to model All Transmission Operator areas contiguous its own Transmission Operator area. This requirement is unlike its brothers in MOD-028 and MOD-030 which allow to model with equivalent. We understand that one could interpret the wording of the standard as in fact allowing the modeling with equivalent, but then it shows that the language of the standard is not clear enough. |
| Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| Kansas City Power & Light Co. | Requirements state that the Transmission Operator performs functions that are currently performed by the SPP Transmission Service Provider for KCPL. Suggest adding "or Transmission Service Provider" after "Transmission Operator" in all requirements so that either entity could perform these tasks. |
| Response: The Transmission Operator is responsible for handling the issues on the real-time system. Therefore, the Drafting Team believes the Transmission Operator is the appropriate entity to select the methodology, rather than be forced to implement the method selected by the Transmission Service Provider. The Transmission Operator has the ability to delegate the responsibility to the Transmission Service Provider if desired. | |
| National Grid | MOD-028 allows for the equivalent representation of radial lines and facilities 161kV or below and the equivalent representation for immediately adjacent and beyond Reliability Coordination areas. This standard, MOD-029 does not allow for this equivalency. We feel that like MOD-028, MOD-029 should have this same equivalency (with clarification of the 161kV). |
| Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| New Brunswick Power Transmission Corporation | Take exception to the allowance given for any equivalent modeling of neighboring areas. |
| Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| New York | There is an issue with no allowance for any equivalent modeling of neighboring areas( which is specified in MOD 28-1) |

| Entity | Comment |
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| Power Authority | |
| Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| Northeast Utilities | No allowance for any equivalent modeling of neighboring areas (which is specified in MOD-28-1). |
| Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| PacifiCorp | PacifiCorp appreciates the work completed to date on MOD-029, Rated System Path Methodology, and the opportunity to continue to participate in the standards development process.<br>In reviewing MOD-029, PacifiCorp has a remaining concern regarding the Severe Violation Severity Level for R7 that reads "The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements" (emphasis added). The calculation for firm ATC in R7 in the version posted for initial ballot includes incrementing firm ATC for firm counterflows. In the Rated System Path Methodology, PacifiCorp does not use counterflows to increment firm ATC because flows change in real time and may not allow additional firm transfer capability in the opposite direction to be relied upon. Taken further, considering scheduling practices for firm transmission reservations additional transfer capability should not be considered firm for either counterflows or counter schedules. Respecting a transmission customer's right to change schedules against a reservation up to 20 minutes before the hour gives little assurance to a transmission customer relying on any incremental transfer capability created in the opposite direction above and beyond the traditional ATC calculation, and as such additional "counter" transfer capability should only be reserved and scheduled as non-firm. The standard language should explicitly allow transmission providers to not include counterflows or counter schedules in their firm ATC calculation.<br>The definition in R7 states that the adjustments for firm counterflows would be as specified in the Transmission Service Provider's Available Transfer Capability Implementation Document described in MOD-001. While R3.2 and R3.3 appear to provide flexibility for the Transmission Service Provider to define how it accounts for counterflows, PacifiCorp's concern is that it does not use counterflows to increment firm ATC. In practice, most transmission providers in the west using the Rated System Path Methodology do not use counterflows as defined in the formula, PacifiCorp is concerned that it would not satisfy the requirement as discussed above and the Transmission Service Provider would be in violation by not using "all elements defined in R7, or used additional elements" (emphasis added). It should be clear that the use of counter schedules would not be interpreted as an "additional element."<br>To alleviate this concern, PacifiCorp recommends two corrections to the proposed standard.<br>1) that the Severe Violation Severity Level for R7 be modified to read "The Transmission Service Provider did not use all the elements defined in R7 and as specified in the Transmission Service Provider's Available Transfer Capability Implementation Document required in MOD-001, when determining firm ATC, or used additional elements"<br>2) that the term counterflows in the firm ATC and non-firm ATC calculation included in R7 and R8 respectively, include a footnote or other language notation that states "May be satisfied under the Rated System Path Methodology without |

| Entity | Comment |
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| | the use of counterflows as defined in the Transmission Service Providers ATCID."<br>With these changes, and assuming no further changes in the standard language elsewhere, PacifiCorp would vote affirmative for this standard. The remaining language in the standard is acceptable to PacifiCorp and appears to align well with the established rating practices for transmission facilities in the Western Interconnection. |
| Response: Your concerns have been addressed in M9 and M10 by adding the highlighted words in the following sentence: Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). | |
| Potomac Electric Power Co. | Potomac Electric agrees with the comments of PJM distributed to the ballot body. I will not repeat them here, but do include the headings:<br>I. The ATC MOD standards should have been sent out for comment not pre-ballot posting.<br>II. Depth of the ATC MOD standards is excessive.<br>III. Determining Violation Risk Factors is incorrect.<br>IV. Determining Violation Severity Levels is incomplete. |
| Response: Please see PJM response. | |
| PP&L, Inc. | Section R10 ETCnf Calculation of Existing Transmission Commitments for non firm (ETCnf) should only include non firm transmission reservations that have energy scheduled on them during the operating horizon.<br>Allowing ATCnf to be decremented by non firm pt to pt reservations, without energy schedules, restricts the utilization of external RTO interfaces. Hoarding of ATC by counterparties who purchase the reservation and do not schedule energy is a possibility.<br><br>It is also not stated what the definition of "set aside" is as it pertains to NITSnf. Please provide a definition of "set aside".<br><br>Again ATCnf should not be decremented by non firm (network service) reservations that are not associated with energy schedules during the operating horizon. The reasons are the same as stated above. |
| Response: The Drafting Team believes that how to account for unscheduled non-firm service in ETC and ATC is an issue to be discussed in NAESB as part of the postback business practice.<br><br>"Set aside" is intended to mean the practice of holding capacity for a committed or expected use. The drafting team believes that this aligns with the common definition of the words used. | |
| Public Service Electric and Gas Co. | PSE&G votes NO for the reasons expressed in PJM's comments. |

| Entity | Comment |
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| Response: Please see PJM response. | |
| Sierra Pacific Power Co. | Voting affirmative with reservation that the VRF's are too high. None should be higher than "lower". These Requirements have zero impact on BES Reliability; they are merely commercial/business practices. |
| Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br>However, the Drafting Team believes that ATC calculations are reliability related. While the Drafting Team does agree that the sale of transmission service and that the underutilization of the transmission system is not a reliability issue, the over-scheduling of the transmission system can have significant reliability implications. An overscheduled condition can require operator intervention; ATC or AFC calculations can provide indicators of the effect planned transfers will have on the transmission system and allows the associated reliability entities to plan accordingly. | |
| Southern Company Services, Inc. | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Westar Energy | Not applicable to SPP |
| Response: No response needed. | |
| Independent Electricity System Operator | Unlike MOD-028, this standard does not explicitly state that one can use equivalent models in their analysis. We are voting for this standard only because we interpret that when R1.1 states that "the model utilizes data and assumptions" - the requirement is indicating that creating equivalent models is included as an "assumption" by the TOP that such models are sufficient to represent the respective areas and that there is no need to explicitly state the use of equivalent models similar to MOD-028.<br>We request the STD to provide this clarification in the standard similar to MOD-0028 for the re-circulation ballot. If our interpretation is incorrect, then we are totally against this standard and will cast a negative ballot during re-circulation |
| Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| ISO New | ISO New England believe this Standard, similar to MOD-028, should allow for equivalence modeling. |

| Entity | Comment |
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| England, Inc. | |
| Response: MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| New York Independent System Operator | The NYISO's December 14 comments requested that the SDT revise requirements R2.3 and R2.6 of MOD-029, or, in the alternative, clarify that they do not apply to transmission providers, such as the NYISO, that do not offer physical transmission rights based on contract-path reservations. The SDT did not take either of these actions so the NYISO respectfully renews its request.<br>Response: The drafting team believes the standards are currently drafted correctly.<br><br>The December 14 comments also requested that the definition of OS(F) in the ETC calculation algorithms in MOD-029 (R.6 and R.7) be revised to conform to the corresponding definitions in MOD-028 (R.9 and R. 10). The SDT has revised the definitions in MOD-029 to establish that OS(F) elements should be specified in the ATCID but has not made the requested change. The NYISO respectfully renews its request.<br>Response: In the Rated System Path methodology simultaneous impact to the path is taken into account in the determination TTC, not $OS_{f,}$ (which is a component of ETC).<br><br>Consistent with the NYISO's "general" comments submitted in response to MOD-001, none of the violation risk factors in MOD-029 should have a rating beyond "Lower," the proposed violation severity levels should be reviewed so that they include appropriate gradations, and reliability requirements should not be adopted in areas that are better left to NAESB or to the individual practices of Reliability Coordinators, Transmission Operators, Transmission Service Providers and/or Transmission Planners, etc..<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br>The drafting team also modified many of the VSLs to have more than one level. The Drafting Team believes that ATC calculations are reliability related. While the Drafting Team does agree that the sale of transmission service and that the underutilization of the transmission system is not a reliability issue, the over-scheduling of the transmission system can have significant reliability implications. An overscheduled condition can require operator intervention; ATC or AFC calculations can provide indicators of the effect planned transfers will have on the transmission system and allows the associated reliability |

| Entity | Comment |
|---|---|
| | entities to plan accordingly.<br><br>The NYISO's December 14 Comments also explained that it was critically important that the definition of "Existing Transmission Commitments" ("ETC") in MOD-028 and -029 be interpreted flexibly. Many of the variables in the proposed ETC algorithm will not be applicable (or will always have a value of zero) in the NYISO's case. On the other hand, the most important input into the NYISO's ATC calculations is "Transmission Flow Utilization," which is based on the security constrained network powerflow solutions determined by the NYISO's day-ahead and real-time market software. The NYISO described how the OS(F) variable in the proposed ETC algorithm appeared to be broad enough for the NYISO to include Transmission Flow Utilization information when calculating ETC (and thus ATC). The NYISO added that it could provide additional information concerning its market software's computation of Transmission Flow Utilization and its role in the ETC calculation in its Available Transfer Capability Implementation Document ("ATCID"). The NYISO requested further that if its interpretation were incorrect that the MOD-028 and MOD-029 definition of ETC (and/or OS(F)) be revised to expressly allow ISO/RTO market software results, such as the NYISO's Transmission Flow Utilization information, to be considered in ETC calculations. Otherwise, the NYISO's existing method of calculating and posting ATC using market software outputs, which is a core feature of its FERC-approved market design, would be in conflict with NERC's standard. The SDT has subsequently made certain revision to the OS(F) definitions in MOD-028 and -029. None of the revisions responds to the NYISO's comments. Therefore, absent some contrary statement from NERC, the NYISO will assume that it has correctly interpreted the OS(F) definition as sufficiently broad to allow for the inclusion of Transmission Flow Utilization information when calculating ETC and ATC.<br>Response: The SDT does not disagree with NYISO's understanding; however, interpretation of a standard has its own due process established in NERC and NYISO should pursue that process if it wants more certainty.<br><br>Finally, the NYISO has previously noted that NERC's December request for an extension of time to file the proposed MOD standards described MOD-029 as a methodology used "exclusively" in the Western Interconnection. The December 14 Comments sought clarification that NERC was not proposing to restrict the use of MOD-029 (or MOD-028) to particular geographic regions. The text of the proposed standards is silent on this question. At the same time, NERC's March 3 Standards Announcement referred to MOD-028 and -029 as being "performed primarily" in the Eastern and Western Interconnections respectively, with no suggestion that either methodology is "exclusive" to those regions. Therefore, absent a statement to the contrary by NERC, the NYISO will assume that there are no geographic restrictions on a Transmission Service Providers' ability to adopt MOD-029 (or MOD-28)<br>Response: NYISO is correct none of the standards are restricted to a geographic region. Further, any Transmission Service Provider can choose any of the methodologies. Refer to MOD-01 R.1. and footnote 1 for R.1 |
| Response: Please see in-line responses. | |
| PJM Interconnection, | While PJM will not choose the method specified in MOD-029 PJM believes changes needed to make MOD-030 acceptable would cause the need for changes to similar requirements in MOD-029. |

| Entity | Comment |
|---|---|
| L.L.C. | |
| Response: The Drafting Team has endeavored to make MOD-029 consistent with any changes made to MOD-030. | |
| Alabama Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Bonneville Power Administration | R2.2 Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the maximum flow that can be simulated. |
| Response: MOD-029 R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS). In that case the TTC in the non-prevailing direction will be limited to the greater of the flow that can be simulated in the non-prevailing direction or the TTC that can be achieved in the prevailing flow direction without the use of the SPS. | |
| Consolidated Edison Co. of New York | R1.1.1.2 should be revised to allow for the use of equivalents (in lieu of detailed modeling of neighboring areas). |
| Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| Dominion Resources, Inc. | In support of PJM and NPPC comments |
| Response: Please see PJM response. | |
| Georgia Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Gulf Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Hydro One Networks, Inc. | Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighbouring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that |

| Entity | Comment |
|---|---|
| | these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained.<br>In addition we offer the following comments to specific Standard MOD-029:<br>– As drafted, the Standard does not permit any equivalent modeling of neighboring areas (which is permitted in MOD-028-1). |
| Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.<br>MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| MidAmerican Energy Co. | I believe this standard will not apply to us. |
| Response: No response needed. | |
| Mississippi Power | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| New York Power Authority | MOD-029-1--recommendation to vote NO not to accept NPCC RSC has an issue with no allowance for any equivalent modeling of neighboring areas (which is specified in MOD-28-1). |
| Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| Public Service Electric and Gas Co. | PSE&G votes NO for the reasons expressed in PJM's comments. |
| Response: Please see PJM response. | |
| Madison Gas and Electric Co. | We believe the standard does not apply to MRO members. |
| Response: No response needed. | |
| Bonneville Power Administration | I vote yes but suggest that R 2.2 be reworded as follows:<br>R2.2 "Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction maximum flow that can be simulated." |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td></td><td>The justification for this wording change stems from system reliability concerns surrounding "future" electrical system changes that would enable a higher transfer on a system that, prior to the system change, could not achieve this flow. A higher TTC would be allowed after the system reliability considerations at the higher TTC have been satisfied.</td></tr>
<tr><td colspan="2">Response: MOD-029 R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS). In that case the TTC in the non-prevailing direction will be limited to the greater of the flow that can be simulated in the non-prevailing direction or the TTC that can be achieved in the prevailing flow direction without the use of the SPS.</td></tr>
<tr><td>Calpine Corporation</td><td>The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose.<br><br>We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency.<br><br>The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document, is difficult to evaluate if it is not yet determined which parties will have access to the document.<br><br>Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization. In calculating the ATC or AFC as applicable, a significant factor in the calculations will be the assumed counterflows and postbacks. The standards provide no guidance on these terms, but rather leave them entirely to the discretion of the TSP, subject only to documentation of their assumptions in the ATCID, which might not be visible to market participants.</td></tr>
<tr><td colspan="2">Response: NAESB is responsible for determining which information will be shared with market participants. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation.</td></tr>
<tr><td>Electric Power Supply Association</td><td>The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose.<br><br>We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency.<br><br>The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions</td></tr>
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| Entity | Comment |
|---|---|
| | represents a substantial improvement over the status quo. However, the utility of this document, is difficult to evaluate if it is not yet determined which parties will have access to the document.<br>Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization. In calculating the ATC or AFC as applicable, a significant factor in the calculations will be the assumed counterflows and postbacks. The standards provide no guidance on these terms, but rather leave them entirely to the discretion of the TSP, subject only to documentation of their assumptions in the ATCID, which might not be visible to market participants. |
| Response: NAESB is responsible for determining which information will be shared with market participants. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation. | |
| PPL Generation LLC | Section R10 ETCnf Calculation of Existing Transmission Commitments for non firm (ETCnf) should only include non firm transmission reservations that have energy scheduled on them during the operating horizon.<br>Allowing ATCnf to be decremented by non firm pt to pt reservations, without energy schedules, restricts the utilization of external RTO interfaces. Hoarding of ATC by counterparties who purchase the reservation and do not schedule energy is a possibility. It is also not stated what the definition of "set aside" is as it pertains to NITSnf.<br>Please provide a definition of "set aside".<br>Again ATCnf should not be decremented by non firm (network service) reservations that are not associated with energy schedules during the operating horizon. The reasons are the same as stated above. |
| Response: The Drafting Team believes that how to account for unscheduled non-firm service in ETC and ATC is an issue to be discussed in NAESB as part of the postback business practice. “Set aside” is intended to mean the practice of holding capacity for a committed or expected use. The drafting team believes that this aligns with the common definition of the words used. | |
| PSEG Power LLC | PSEG Power LLC votes no for the reasons expressed in PJM's comments. |
| Response: Please see PJM response. | |
| Barry Green Consulting Inc. | Transparency: The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the standard that is being balloted, the word "transparency" has been deleted from the purpose.<br>We also note that a requirement that sufficient data be exchanged to allow for validation of the ATC calculation is included but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency.<br>The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions |

| Entity | Comment |
|---|---|
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| Response: NAESB is responsible for determining which information will be shared with market participants. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation. | |
| Bonneville Power Administration | R2.2 Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the maximum flow that can be simulated.<br>The justification for this wording change stems from system reliability concerns surrounding "future" electrical system changes that would enable a higher transfer on a system that, prior to the system change, could not achieve this flow. A higher TTC would be allowed after the system reliability considerations at the higher TTC have been satisfied. |
| Response: MOD-029 R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS). In that case the TTC in the non-prevailing direction will be limited to the greater of the flow that can be simulated in the non-prevailing direction or the TTC that can be achieved in the prevailing flow direction without the use of the SPS. | |
| Consolidated Edison Co. of New York | R1.1.1.2 should allow for the use of equivalents. |
| Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| Dominion Resources, Inc. | Support comments provided by NPCC and PJM |
| Response: Please see PJM response. | |
| PP&L, Inc. | Section R10 ETCnf Calculation of Existing Transmission Commitments for non firm (ETCnf) should only include non firm transmission reservations that have energy scheduled on them during the operating horizon. Allowing ATCnf to be decremented by non firm pt to pt reservations, without energy schedules, restricts the utilization of external RTO interfaces. Hoarding of ATC by counterparties who purchase the reservation and do not schedule energy is a possibility. It is also not stated what the definition of "set aside" is as it pertains to NITSnf. |

| Entity | Comment |
|---|---|
| | Please provide a definition of "set aside".<br>Again ATCnf should not be decremented by non firm (network service) reservations that are not associated with energy schedules during the operating horizon. The reasons are the same as stated above. |
| Response: The Drafting Team believes that how to account for unscheduled non-firm service in ETC and ATC is an issue to be discussed in NAESB as part of the postback business practice. “Set aside” is intended to mean the practice of holding capacity for a committed or expected use. The drafting team believes that this aligns with the common definition of the words used. | |
| PSEG Energy Resources & Trade LLC | PSEG Energy Resources & Trade votes NO for the reasons expressed by PJM in its ballot. |
| Response: Please see PJM response. | |
| Commonwealth of Massachusetts Department of Public Utilities | Massachusetts DPU has an issue with no allowance for any equivalent modeling of neighboring areas, which is specified in MOD-028-1. |
| Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| National Association of Regulatory Utility Commissioners | The standard should provide for equivalent modeling of neighboring systems below a certain level. |
| Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |
| Wyoming Public Service Commission | Sufficient flexibility should be allowed to regional and subregional planners so that they could, under the right circumstances, seek new and workable ways to accommodate intermittent generation resources when there is actual transmission capacity available but not covered by contracted allocations. |
| Response: The Drafting Team does not believe the standard prohibits the use of intermittent generation resources. If Wyoming Public Service Commission believes otherwise, please detail the potential conflicts in future comments. | |
| Midwest Reliability | The MRO believes the standard does not apply to MRO members. |

| Entity | Comment |
| --- | --- |
| Organization | |
| Response: No response needed. | |
| Northeast Power Coordinating Council, Inc. | The standard should allow for equivalent modeling of neighboring systems. |
| Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs. | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

## A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining TTC: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

**R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

**R1.3.** Any contractual obligations for allocation of TTC.

**R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.

**R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.5.1.** Define if the source used for ATC calculations is obtained from the source field or the POR field of the transmission reservation

**R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the POD field of the transmission reservation

**R1.5.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.5.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

**R2.** When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities161kV or below is allowed.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs (for intra-day and next-day) for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R3.1.** For on-peak intra-day TTCs, and on-peak next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R3.1.2.** Load forecast for the on-peak period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For off-peak intra-day and off-peak next-day TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

**R3.2.2.** Load forecast for the off-peak period being calculated.

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.** When calculating TTCs (for time periods beyond next day) for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** For days two through 31 TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R4.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R4.1.2.** Load forecast for the day being calculated.

**R4.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.2.** For months two through 13 TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R4.2.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R4.2.2.** Load forecast for the month calculated.

**R4.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R5.** When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** Use all Contingencies meeting the criteria described in its ATCID.

**R5.2.** Respect any contractual allocations of TTC.

**R5.3.** Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate

representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

**R6.** Each Transmission Operator shall calculate TTC for each ATC Path as defined below, unless otherwise requested by the Transmission Service Provider: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** At least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations.

**R6.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R6.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer in duration.

**R7.** Each Transmission Operator shall calculate TTC for each ATC Path using the following process: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R7.1.** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

**R7.2.** If the limit in step R7.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R7.3.** Use (as the TTC) the lesser of:

- The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or
- The sum of Facility Ratings of all ties comprising the ATC Path.

**R7.4.** For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed that Transmission Operator's contractual rights.

**R8.** The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R8.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

**R8.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

**R9.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

$\mathbf{NITS_F}$ is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

$\mathbf{GF_F}$ is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the

[1] The Transmission operator may honor distribution factors less than 5% if desired.

effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R10.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_{NF}$** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R11.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + Counterflows_F$$

**Where:**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm ATC due to a change in the use of Firm Transmission Service for that period, as defined in Business Practices.

**$Counterflows_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

**R12.** When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + Counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm ATC due to a change in the use of Non-Firm Transmission Service for that period, as defined in Business Practices.

**$Counterflows_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3) (R4)

**M4.** Each Transmission Operator shall provide the contingencies used in determining TTC and its ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R5)

**M5.** Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R5.2. (R5)

**M6.** Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R5.3, and that estimated scheduled interchange was included in the determination of TTC. (R5)

**M7.** Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to calculate TTCs at specific intervals) that TTCs have been calculated at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R6.(R6)

**M8.** Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R7. (R7)

**M9.** Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R8. (R8)

**M10.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ETC used the algorithm and elements described in R9 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R9)

**M11.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ETC used the algorithm and the elements described in R10 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R10)

**M12.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ATC used the algorithm and the elements described in R11 and does not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R11)

**M13.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ATC used the algorithm and the elements described in R12 and does not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R12)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 and R4 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R5, R6, R7 and R8 for the most recent12 months.
- The Transmission Service Provider shall retain evidence to show compliance with R9, R10, R11 and R12 for the most recent12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has an ATCID that meets the intent of Requirement 1 but the ATCID is missing some minor information. | The Transmission Service Provider has an ATCID but it is missing one of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing two of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing three or more of the four required elements in R1. |
| R2. | The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>**OR**<br>The Transmission Operator did not include in the Transmission model modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator area.<br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>**OR**<br>The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator area.<br>**OR**<br>The Transmission Operator did not include in the Transmission model modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator areas.<br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | modeled. |
| R3. | The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID.. | The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.. | In calculating TTCs for intra-day and next-day, the Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.<br>**OR**<br>In calculating TTCs for intra-day and next-day, the Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3.1. |
| R4. | N/A | N/A | N/A | In calculating TTCs for time periods beyond next day, the Transmission Operator did not include more than fifty expected generation and Transmission outages, additions or retirements in the TTC process.<br>**OR**<br>In calculating TTCs for time periods beyond next-day, the Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R4.1. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R5. | N/A | N/A | N/A | The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br>**OR**<br>The Transmission Operator did not respect contractual allocations of TTC.<br>**OR**<br>The Transmission Operator did not model reservations' sources or sinks as described in R5.3<br>**OR**<br>The Transmission Operator did not use firm reservations to estimate interchange or did not utilize that estimate in the TTC calculation as described in R5.3. |
| R6. | N/A | N/A | N/A | The Transmission Operator did calculated TTCs in excess of the minimum time frames specified in R6. |
| R7. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the process specified in R7. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R8. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.<br>**OR**<br>The Transmission Operator t provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination<br>**OR**<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations.<br>**OR**<br>The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination<br>**OR**<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations. |
| R9. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R9 when determining firm ETC, or used additional elements. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R10. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R10 when determining non-firm ETC, or used additional elements. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R11 when determining firm ATC, or used additional elements. |
| R12. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R12 when determining non-firm ATC, or used additional elements. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes ~~the modifications identified in the SAR with~~ consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

## A. Introduction

1. **Title: Area Interchange Methodology**
2. **Number: MOD-028-1**
3. **Purpose:** To increase consistency and ~~transparency~~ reliability in the development and documentation of ~~T~~transfer ~~C~~capability calculations for short-term ~~Transmission services~~ use performed by entities using the Area Interchange Methodology to support ~~reliable~~ analysis and system operations.
4. **Applicability:**
   **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ~~Posted~~ ATC Paths.
   **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ~~Posted~~ ATC Paths.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that ~~all six (~~MOD-001-1, ~~MOD-004-1, MOD-008-1,~~ MOD-028-1, MOD-029-1, and MOD-030-1~~) ATC-related standards~~ are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining TTC: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations ~~may~~ can be validated.

**R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

**R1.3.** Any contractual obligations for allocation of TTC.

**R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.

**R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.5.1.** Define if the source used for ATC calculations is obtained from the source field or the POR field of the transmission reservation

**R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the POD field of the transmission reservation

**R1.5.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.5.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

**R2.** When calculating TTC for ~~Posted~~ ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities161kV or below is allowed.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs (for intra-day and next-day~~-~~) for ~~Posted~~ ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's ~~Area~~area.~~,~~ The Transmission Operator shall also include~~all~~ the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers~~,~~ and ~~any of the following data provided by~~ any other Transmission Service Providers with which coordination agreements have been executed:~~.,~~ ~~provided that data can be associated with Facilities that are explicitly represented in the Transmission model:~~ [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R3.1.** For on-peak intra-day TTCs, and on-peak next-day ~~intra-peak~~ TTCs, use the following (a~~t a minimum~~s well as any other values and additional parameters as specified in the ATCID):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R3.1.2.** ~~Peak~~ Load forecast for the on-peak period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For off-peak intra-day and off-peak next-day TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID~~at a minimum~~):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

**R3.2.2.** ~~Peak~~ Load forecast for the off-peak period being calculated.

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.** When calculating TTCs (for time periods beyond next day) for ~~Posted~~ ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's a~~A~~rea. The Transmission Operator shall also include~~, all~~ the following data associated with Facilities that are explicitly represented in the Transmission model as provided by adjacent Transmission Service Providers~~,~~ and any ~~of the following data provided by any~~ other Transmission Service Providers with which coordination agreements have been executed~~, provided that data can be associated with Facilities that are explicitly represented in the Transmission model~~: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** For days two through 31 TTCs, use the following (a~~t a minimum~~s well as any other values and additional parameters as specified in the ATCID):

**R4.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R4.1.2.** ~~Peak~~ Load forecast for the day being calculated.

**R4.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.2.** For months two through 13 TTCs, use the following (a~~t a minimum~~s well as any other values and additional parameters as specified in the ATCID):

**R4.2.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R4.2.2.** ~~Peak~~ Load forecast for the month calculated.

**R4.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R5.** When calculating TTCs for ~~Posted~~ ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** Use all Contingencies meeting the criteria described in its ATCID.

**R5.2.** Respect any contractual allocations of TTC.

**R5.3.** Include, for each time period, the ~~expected schedules using monthly or longer~~ F~~f~~irm Transmission ~~s~~Service expected to be scheduled as specified in the ATCID~~,~~ (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers)~~,~~ for the Transmission Service Provider~~'s Area~~, all adjacent Transmission

Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been ~~specified~~ identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been ~~specified~~ identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" ~~modeled~~ in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been ~~specified~~ identified in the reservation and the point cannot be mapped to a discretely modeled point ~~or~~ , an "equivalence," or an "aggregate representation" ~~modeled~~ in the Transmission Service Provider's Transmission model, use the ~~interface point with the adjacent upstream~~immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been ~~specified~~identified in the reservation, use the immediately adjacent Balancing Authority associated with the ~~interface point with the adjacent upstream~~ Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, -has been ~~specified~~ identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, -has been ~~specified~~ identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation"~~modeled~~ in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, -has been ~~specified~~ identified in the reservation and the point can not be mapped to a discretely modeled point ~~or~~, an "equivalence," or an "aggregate representation" ~~modeled~~ in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the ~~interface point with the adjacent downstream~~ Transmission Service Provider to which the power is to be delivered as the sink.
- If the sink, as specified in the ATCID, -has not been ~~specified~~identified in the reservation, use the immediately adjacent Balancing Authority associated with the ~~interface point with the adjacent downstream~~ Transmission Service Provider to which the power is being delivered as the sink.

**R6.** Each Transmission Operator shall calculate TTC for each ~~Posted~~ ATC Path as defined below, unless otherwise requested by the Transmission Service Provider: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** At least once ~~per~~in the calendar week prior to the specified period for TTCs used in hourly~~,~~ and daily ATC calculations.

**R6.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R6.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer in duration.

**R7.** Each Transmission Operator shall calculate TTC for each ~~Posted~~ ATC Path using the following process: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R7.1.** Determine the incremental Transfer Capability for each ~~Posted~~ ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is ~~greater than~~ 5% or greater[1].
-

**R7.2.** If the limit in step R7.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R7.3.** ~~Sum the incremental Transfer Capability and all impacts of Firm Transmission Service that were included in the study model~~Use (as the TTC) the lesser of:

– The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or

– The sum of Facility Ratings of all ties comprising the ~~Posted~~ ATC Path.

**R7.4.** For ~~Posted~~ ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed that Transmission Operator's contractual rights.

[1] The Transmission operator may honor distribution factors less than 5% if desired.

**R8.** The Transmission Operator shall provide the Transmission Service Provider of that ~~Posted~~ ATC Path with the most current value for TTC for that ~~Posted~~ ATC Path no more than: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R8.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

**R8.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

~~**R7.1.** within seven calendar days of its determination.~~

**R9.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for an ~~Posted~~ ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NITS_F$** is the firm capacity ~~reserved~~ set aside for Network Integration Transmission Service ~~reserved~~ (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ~~Posted~~ ATC Paths that serve as interfaces with other ~~Transmission Service Providers~~Balancing Authorities.

**$GF_F$** is the firm capacity ~~reserved~~ set aside for Grandfathered Firm Transmission Service and ~~bundled~~ contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts ~~on~~ from other ~~Posted~~ ATC Paths of the Transmission Service Provider as ~~described~~ specified in the ATCID.

**R10.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for an ~~Posted~~ ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity ~~reserved~~ set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ~~Posted~~ ATC Paths that serve as interfaces with other ~~Transmission Service Providers~~Balancing Authorities.

**$GF_{NF}$** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and ~~bundled~~ contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from ~~on~~ other ATC~~Posted~~ Paths of the Transmission Service Provider as ~~described~~ specified in the ATCID.

**R11.** When calculating f~~F~~irm ATC for an ~~Posted~~ ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + Counterflows_F$$

**Where:**

**$ATC_F$** is the firm Available Transfer Capability for the ~~Posted~~ ATC Path for that period~~,~~.

**TTC** is the Total Transfer Capability of the ~~Posted~~ ATC Path for that period~~,~~.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ~~Posted~~ ATC Path during that period~~,~~.

**CBM** is the Capacity Benefit Margin for the ~~Posted~~ ATC Path during that period~~,~~.

**TRM** is the Transmission Reliability Margin for the ~~Posted~~ ATC Path during that period~~,~~ .

**$Postbacks_F$** are ~~adjustments~~ changes to firm ATC due to a change in the use of Firm Transmission Service~~postbacks~~ for that period, as defined in Business Practices~~, and~~.

**$Counterflows_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and ~~described~~ specified in the~~ir~~ ATCID.

**R12.** When calculating ~~N~~non-f~~F~~irm ATC for a ~~Posted~~ ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + Counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ~~Posted~~ ATC Path for that period~~,~~.

**TTC** is the Total Transfer Capability of the ~~Posted~~ ATC Path for that period~~,~~.

**$ETC_{F}$** is the sum of existing firm Transmission commitments for the ~~Posted~~ ATC Path during that period~~,~~.

**$ETC_{NF}$** is the sum of existing non-firm Transmission commitments for the ~~Posted~~ ATC Path during that period~~,~~.

**$CBM_{S}$** is the Capacity Benefit Margin for the ~~Posted~~ ATC Path that has been scheduled without a separate reservation ~~on~~ during that period~~,~~.

**$TRM_{U}$** is the Transmission Reliability Margin for the ~~Posted~~ ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period~~,~~.

**$Postbacks_{NF}$** are ~~adjustments~~ changes to non-firm ATC due to a change in the use of Non-Firm Transmission Service~~postbacks~~ for that period, as defined in Business Practices~~, and~~.

**$Counterflows_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and ~~described~~ specified in the~~ir~~ ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** Each~~The~~ Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** Each~~The~~ Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3) (R4)

**M4.** Each~~The~~ Transmission Operator shall provide the contingencies used in determining TTC and its ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R5)

**M5.** Each~~The~~ Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R5.2. (R5)

**M6.** Each~~The~~ Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that ~~monthly or longer~~firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R5.3, and that estimated scheduled interchange was included in the determination of TTC. (R5)

**M7.** Each~~The~~ Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to calculate TTCs at specific intervals) that TTCs have been calculated at least once ~~per~~ in the calendar week prior to the specified period for TTCs used in hourly~~,~~ and daily ATC calculations, ~~and~~ at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R6.(R6)

**M8.** Each~~The~~ Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R7. (R7)

**M9.** Each ~~The~~ Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it~~s~~ provided its Transmission Service Provider with the most current values for TTC in accordance with R8. (R8)

**M10.** Each~~The~~ Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of f~~F~~irm ETC used the algorithm and elements described in R9 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R9)

**M11.** Each~~The~~ Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of n~~N~~on-f~~F~~irm ETC used the algorithm and the elements described in R10 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R10)

**M12.** Each~~The~~ Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of ~~F~~firm ATC used the algorithm and the elements described in R11 and does not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R11)

**M13.** Each~~The~~ Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of n~~N~~on-f~~F~~irm ATC used the algorithm and the elements described in R12 and does not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R12)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 and R4 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R5, R6, R7 and R8 for the most recent12 months.
- The Transmission Service Provider shall retain evidence to show compliance with R9, R10, R11 and R12 for the most recent12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has an ATCID that meets the intent of Requirement 1 but the ATCID is missing some minor information. | The Transmission Service Provider has an ATCID but it is missing one of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing two of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing three or more of the four required elements in R1. |
| R2. | The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission or Generation~~or~~ Owner in their Transmission model~~ and one of those Facility Ratings was used (or should have been used) to establish TTC for one or more Posted ATC Paths~~. ~~An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized.~~<br><br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generation~~or~~ Owner in their Transmission model~~ and two to five of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted ATC Paths~~. ~~An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized.~~<br><br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generation~~or~~ Owner in their Transmission model~~ and six to ten of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted ATC Paths~~. ~~An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized.~~<br><br>**OR**<br><br>The Transmission Operator did not include in the Transmission model modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator area.<br><br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been | The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission or Generation~~or~~ Owner in their Transmission model~~ and eleven or more of those Facility Ratings were used (or should have been used) to establish a TTC for one or more Posted ATC Paths~~. ~~An inaccurate Facility Rating is a single violation, regardless how many times that Facility Rating has been utilized.~~<br><br>**OR**<br><br>The Transmission Operator's model ~~did not include in the Transmission model~~ includes equivalent representation of non-radial facilities greater than 161 kV ~~detailed modeling data and topology~~ for its own Reliability Coordinator area.<br><br>**OR**<br><br>The Transmission Operator did |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | modeled. | not include in the Transmission model ~~detailed~~ modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator areas.<br><br>A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. |
| R3. | The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID.~~in the TTC process.~~ | The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID.~~in the TTC process~~. | The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.~~in the TTC process~~. | In calculating TTCs for intra-day and next-day, the Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.~~ in the TTC process.~~<br><br>**OR**<br><br>In calculating TTCs for intra-day and next-day, the Transmission Operator did not include the ~~peak~~ Load forecast or unit commitment in its TTC calculation as described in R3.1. |
| R4. | N/A | N/A | N/A | In calculating TTCs for time periods beyond next day, the Transmission Operator did not include more than fifty expected generation and Transmission outages, additions or retirements in the TTC process. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | **OR**<br>In calculating TTCs for time periods beyond next-day, the Transmission Operator did not include the ~~peak~~ Load forecast or unit commitment in its TTC calculation as described in R4.1. |
| R5. | N/A | N/A | N/A | The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br>**OR**<br>The Transmission Operator did not respect contractual allocations of TTC.<br>**OR**<br>The Transmission Operator did not model reservations' sources or sinks as described in R5.3<br>**OR**<br>The Transmission Operator did not use ~~monthly or longer~~ firm reservations to estimate interchange or did not utilize that estimate in the TTC calculation as described in R5.3. |
| R6. | N/A | N/A | N/A | The Transmission Operator did ~~not~~ calculated TTCs ~~per the~~in excess of the minimum time frames specified in R6. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R7. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the ~~minimum time frames~~process specified in R7. |
| R8. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.<br>**OR**<br>The Transmission Operator ~~has no~~t provided its Transmission Service Provider with its ~~Posted ATC~~ Path TTCs used in monthly ATC calculations ~~within~~ more than seven calendar days ~~of~~ after their determination, but ~~is has~~ not ~~been~~ more than 14 calendar days since their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ~~Posted ATC~~ Path TTCs used in monthly ATC calculations ~~within~~more than 14 calendar days after~~of~~ their determination, but ~~is has~~ not been more than 21 calendar days ~~since~~ after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ~~Posted ATC~~ Path TTCs used in monthly ATC calculations ~~within~~more than 21 calendar days after~~of~~ their determination, but ~~is has~~ not been more than 28 calendar days ~~since~~ after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination<br>**OR**<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations.<br>**OR**<br>The Transmission Operator ~~has not~~ provided its Transmission Service Provider with its ~~Posted ATC~~ Path TTCs used in monthly ATC calculations ~~within~~ more than 28 ~~or more~~ calendar days ~~of~~ after their determination<br>**OR**<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R9. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R9 when determining firm ETC, or used additional elements. |
| R10. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R10 when determining non-firm ETC, or used additional elements. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R11 when determining firm ATC, or used additional elements. |
| R12. | N/A | N/A | N/A | The Transmission Service Provider did not use all the elements defined in R12 when determining non-firm ATC, or used additional elements. |

# Implementation Plan for Standard MOD-028-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-028-1, which describes the Area Interchange methodology (previously referred to as the Network Response ATC methodology) for determining ATC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

## Modified Standards

This standard incorporates the following requirements from FAC-012-1:

– R1 (Documentation of the Transfer Capability Methodology)

– R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

– R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013-1:

– R1 (Calculation of the Transfer Capabilities)

– R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-028-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

## Summary Consideration of Comments:

The Drafting Team has reviewed the comments and made some changes to the standard to address these comments.

1. All VRFs were set to "Lower" in response to industry comments.. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
2. A more graded approach was applied to the VSLs where appropriate.
3. During the review of the VSLs and Measures, it was determined that the measures for R8, R9, R10, and R11 did not adequately measure compliance with the requirements. The drafting team updated the measures and VSLs to ensure that they captured the need to have accurate and valid numbers used in the requirements.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/standards/newstandardsprocess.html.

| Entity | Comment |
|---|---|
| CenterPoint Energy | ERCOT's filed comments to the SDT that ATC, TTC, CBM, and TRM are not applicable within ERCOT operations and that these Standards should have provisions that make it clear that these requirements apply only within market structures in which they are pertinent were ignored by the SDT. These standards should not apply to ERCOT, thus our negative vote. |
| Response: MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any path for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT, and would not require implementation of any methodology, including this standard. | |
| Consolidated Edison Co. of New York | R2 applies to TOP, but R2.1 refers to RC - why the switch? R2.1 should address TOP. |
| Response: It is not a switch; R2 and all of its sub-requirements specify how the Transmission Operator will model the Transmission Operator's Reliability Coordinator area and adjacent Reliability Coordinator areas. There is no action for the Reliability Coordinator in R2; R2.1 intends to covers the Reliability Coordinator's area for modeling purposes by the Transmission Operator, not the RC. The drafting team does not believe any change is necessary. | |
| Duke Energy Carolina | The RC's SOL methodology in FAC-011 is required to include generator contingencies. MOD-028 requires the TO to calculate incremental TTC without exceeding SOLs. If the TTC calculation is performed by scaling generation, then generator contingencies should not have to be considered in addition to the scaling, for the purpose of assuring SOLs are not exceeded. |
| Response: When scaling generation, you are not simulating a contingency – you are just changing dispatch to simulate a transaction. The SDT does not see a conflict. | |
| Great River Energy | GRE does nor support this standard. GRE has concerns with the application of the standard for transmission providers that use flowgates. |
| Response: The SDT does not understand the concern expressed. This standard would not apply to entities that elected to use the flowgate methodology. We do not believe there is any conflict between methodologies. | |
| Hydro One Networks, Inc. | Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighbouring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained, In addition we offer the following comments to the specific Standard MOD-028: Requirement R2.1 introduces a threshold for allowing equivalent representation of radial lines and facilities. The chosen value of "161 kV or below" needs justification. |
| Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.<br>The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally | |

| Entity | Comment |
|---|---|
| accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The 161kV threshold doesn't preclude using a lower threshold for equivalencing if desired. | |
| Kansas City Power & Light Co. | Requirements state that the Transmission Operator is to perform functions that are currently performed by the SPP Transmission Service Provider for KCPL. Suggest adding "or Transmission Service Provider" after "Transmission Operator" in all requirements so that either entity could perform these tasks. |
| Response: The SDT believes it that in the case described, the Transmission Operator can delegate these functions to their Transmission Service Provider. | |
| National Grid | The standard allows when calculating TTC, the Transmission Operator shall use a model that contains the equivalent representation of radial lines and facilities 161kV or below. The 161kV seems arbitrary. We would like clarification as to why "161kV or below" was chosen in section R2.1 for being the threshold for allowing equivalent representation of radial lines and facilities. |
| Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The 161kV threshold doesn't preclude using a lower threshold for equivalencing if desired. | |
| New Brunswick Power Transmission Corporation | Would like clarification on why "161kV or below" was chosen in section R2.1 as being the threshold? |
| Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The 161kV threshold doesn't preclude using a lower threshold for equivalencing if desired. | |
| Northeast Utilities | Would like clarification as to why "161kV or below" was chosen in section R2.1 for being the threshold for allowing equivalent representation of radial lines and facilities. |
| Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The 161kV threshold doesn't preclude using a lower threshold for equivalencing if desired. | |
| Potomac Electric Power Co. | Potomac Electric agrees with the comments of PJM distributed to the ballot body. I will not repeat them here, but do include the headings: I. The ATC MOD standards should have been sent out for comment not pre-ballot posting. II. Depth of the ATC MOD standards is excessive. III. Determining Violation Risk Factors is incorrect. IV. Determining Violation Severity Levels is incomplete. |
| Response: Please see PJM response. | |
| PP&L, Inc. | Confirmed TSR's affect non-firm ATC rather than schedules affecting Non-firm ATC. |
| Response: Confirmed firm TSR's affect Non-firm ATC and unscheduled firm TSR's affect non-firm ATC consistent with postback processes being developed by NAESB. | |
| Public Service Electric and Gas Co. | PSE&G votes NO for the reasons expressed in PJM's comments. |
| Response: Please see PJM response. | |
| Sierra Pacific Power Co. | Not used as a methodology. |
| Response: No response needed. | |
| Southern Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making |

| Entity | Comment |
| --- | --- |
| Services, Inc. | minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| | Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. |
| Western Area Power Administration | No Western office uses the Area Interchange model. |
| | Response: No response needed. |
| ISO New England, Inc. | Would like clarification as to why "161 kV or below" is the threshold for equivalence in R2.1. |
| | Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The 161kV threshold doesn't preclude using a lower threshold for equivalencing if desired. |
| New York Independent System Operator | In its December 14 Comments, the NYISO asked that requirements R3, R4, and R6 under MOD-028 be revised so that TTC would not have to be recalculated when the underlying TTC inputs have not changed. The SDT did not make this revision even though it accepted a similar proposal with respect to the ATC recalculation frequency requirements in what is now R7 under MOD-001 (which the NYISO supports). The NYISO respectfully renews its request that the STD make the requested changes to MOD-028. Under the NYISO system, TTC values do not change often. Accordingly, the proposed MOD-028 requirements would force the NYISO to adopt costly compliance measures that would offer no benefit to its customers.<br>Response: The drafting team did modify requirement R6 under MOD-028 and changed "calculate" to "establish" the TTC values, which allows TTC not to be recalculated when the underlying TTC inputs have not changed but allows the same values with a different time stamp. The drafting team did not modify requirement R3 or R4 under MOD-028 because R3 and R4 do not have any frequency requirements and deal with what is required when TTC is calculated.<br><br>Consistent with the comments provided for MOD I, all of the violation risk factors in MOD-028 should have a rating beyond "Lower," the proposed violation severity levels should be reviewed to ensure so that they include appropriate gradations, and reliability requirements should not be adopted in areas that are better left to NAESB or to the individual practices of Reliability Coordinators, Transmission Operators, Transmission Service Providers and/or Transmission Planners, etc. .<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling. The drafting team has also modified many of the VSLs to have more than one level. The Drafting Team believes that ATC calculations are reliability related. While the Drafting Team does agree that the sale of transmission service and that the underutilization of the transmission system is not a reliability issue, the over-scheduling of the transmission system can have significant reliability implications. An overscheduled condition can require operator |

| Entity | Comment |
|---|---|
| | intervention; ATC or AFC calculations can provide indicators of the effect planned transfers will have on the transmission system and allows the associated reliability entities to plan accordingly.<br><br>The NYISO's December 14 Comments also explained that it was critically important that the definition of "Existing Transmission Commitments" ("ETC") in MOD-028 and -029 be interpreted flexibly. Many of the variables in the proposed ETC algorithm will not be applicable (or will always have a value of zero) in the NYISO's case. On the other hand, the most important input into the NYISO's ATC calculations is "Transmission Flow Utilization," which is based on the security constrained network powerflow solutions determined by the NYISO's day-ahead and real-time market software. The NYISO described how the OS(F) variable in the proposed ETC algorithm appeared to be broad enough for the NYISO to include Transmission Flow Utilization information when calculating ETC (and thus ATC). The NYISO added that it could provide additional information concerning its market software's computation of Transmission Flow Utilization and its role in the ETC calculation in its Available Transfer Capability Implementation Document ("ATCID"). The NYISO requested further that if its interpretation were incorrect that the MOD-028 and MOD-029 definition of ETC (and/or OS(F)) be revised to expressly allow ISO/RTO market software results, such as the NYISO's Transmission Flow Utilization information, to be considered in ETC calculations. Otherwise, the NYISO's existing method of calculating and posting ATC using market software outputs, which is a core feature of its FERC-approved market design, would be in conflict with NERC's standard. The SDT has subsequently made certain revision to the OS(F) definitions in MOD-028 and -029. None of the revisions responds to the NYISO's comments. Therefore, absent some contrary statement from NERC, the NYISO will assume that it has correctly interpreted the OS(F) definition as sufficiently broad to allow for the inclusion of Transmission Flow Utilization information when calculating ETC and ATC.<br>Response: The SDT does not disagree with NYISO's understanding; however, interpretation of a standard has its own due process established in NERC and NYISO should pursue that process if it wants more certainty. |
| Response: Please see in-line responses. | |
| PJM Interconnection, L.L.C. | While PJM will not choose the method specified in MOD-028 PJM believes changes needed to make MOD-030 acceptable would cause the need for changes to similar requirements in MOD-028. |
| Response: The Drafting Team has endeavored to make MOD-028 consistent with any changes made to MOD-030. | |
| Alabama Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Consolidated Edison Co. of New York | R2 applies to TOP, but R2.1 refers to RC - why is there a switch from TOP to RC? R2.1 should address TOP. |
| Response: It is not a switch; R2 and all of its sub-requirements specify how the Transmission Operator will model the Transmission Operator's Reliability Coordinator area and adjacent Reliability Coordinator areas. There is no action for the Reliability Coordinator in R2; R2.1 intends to covers the Reliability Coordinator's area for modeling purposes by the Transmission Operator, not the RC. The drafting team does not believe any change is necessary. | |
| Dominion Resources, Inc. | In support of PJM comments |
| Response: Please see PJM response. | |
| Florida Municipal | Many small Transmission Operators are network service customers of, and are wholly enclosed by, a much larger |

| Entity | Comment |
|---|---|
| Power Agency | TOP/TSP. They have no viable paths or customers in and of themselves and currently their neighboring TOP/TSP handles all of the ATC-related data and calculations mentioned in this standard. In its current draft, this standard puts the onus of calculating TTC squarely on them, when in fact they are not the most appropriate entity for this task. We would suggest changing the Applicability section of this standard (and related standards) to exclude TOP's who are wholly enclosed by a single other TOP, or allow them the choice of deferring to the larger TOP's TTC calculations. We also believe that this standard needs an additional commenting period. |
| Response: The Drafting Team has modified the definition of ATC path, which may address some of your concerns. Additionally, Transmission Operators may delegate tasks to other parties. | |
| Georgia Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Gulf Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Hydro One Networks, Inc. | Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighbouring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained. In addition we offer the following comments to the specific Standard MOD-0028: Requirement R2.1 introduces a threshold for allowing equivalent representation of radial lines and facilities. The chosen value of "161 kV or below" needs justification. |
| Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.<br>The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The specification of 161 kV doesn't preclude using a lower threshold for equivalencing if desired. | |
| MidAmerican Energy Co. | The Transmission Service Provider should be allowed to post contract path quantities for CA to CA paths when reliability means are met with flowgates with ATCs calculated in accordance with MOD-030-1. |
| Response: These standards don't attempt to mandate what may or may not be posted. The Drafting Team is also not clear on what the specific question or comment is with regards to the MOD 28 standard. If we have not answered your questions please rephrase it so that we can respond to it in the upcoming comment period. | |
| Mississippi Power | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |

| Entity | Comment |
|---|---|
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| New York Power Authority | 4) MOD-028-1--recommendation to vote YES to accept, but would like a clarification as to why "161kV or below" was chosen in section R2.1 for being the threshold for allowing equivalent representation of radial lines and facilities. |
| Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The specification of 161 kV doesn't preclude using a lower threshold for equivalencing if desired. | |
| Orlando Utilities Commission | This standard should not include any VRF's with a rating above 'lower'. |
| Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling. | |
| Public Service Electric and Gas Co. | PSE&G votes NO for the reasons expressed in PJM's comments. |
| Response: Please see PJM response. | |
| Wisconsin Public Service Corp. | WPSC does not support this standard. Certain MRO members have concerns with the application of the standard for transmission providers who use flowgates. |
| Response: The SDT does not understand the concern expressed. This standard would not apply to entities that elected to use the flowgate methodology. We do not believe there is any conflict between methodologies. | |
| Florida Municipal Power Agency | Many small Transmission Operators are network service customers of, and are wholly enclosed by, a much larger TOP/TSP. They have no viable paths or customers in and of themselves and currently their neighboring TOP/TSP handles all of the ATC-related data and calculations mentioned in this standard. In its current draft, this standard puts the onus of calculating TTC squarely on them, when in fact they are not the most appropriate entity for this task. We would suggest changing the Applicability section of this standard (and related standards) to exclude TOP's who are wholly enclosed by a single other TOP, or allow them the choice of deferring to the larger TOP's TTC calculations. We also believe that this standard needs an additional commenting period. |
| Response: The Drafting Team has modified the definition of ATC path, which may address some of your concerns. Additionally, Transmission Operators may delegate tasks to other parties. | |
| Madison Gas and Electric Co. | The MRO does not support this standard. Certain MRO members have concerns with the application of the standard for transmission providers that use flowgates. |
| Response: The SDT does not understand the concern expressed. This standard would not apply to entities that elected to use the flowgate methodology. We do not believe there is any conflict between methodologies. | |
| Calpine Corporation | The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td></td><td>amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose. We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency. The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to the document. Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization. In calculating the ATC or AFC as applicable, a significant factor in the calculations will be the assumed counterflows and postbacks. The standards provide no guidance on these terms, but rather leave them entirely to the discretion of the TSP, subject only to documentation of their assumptions in the ATCID, which might not be visible to market participants</td></tr>
<tr><td colspan="2">Response: Response: NAESB is responsible for determining which information will be shared with market participants. While the standard does promote enhanced transparency, the purpose has been reworded to focus more on the reliability aspects of the standard. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation.</td></tr>
<tr><td>Duke Energy</td><td>The RC's SOL methodology in FAC-011 is required to include generator contingencies. MOD-028 requires the TO to calculate incremental TTC without exceeding SOLs. If the TTC calculation is performed by scaling generation, then generator contingencies should not have to be considered in addition to the scaling, for the purpose of assuring SOLs are not exceeded.</td></tr>
<tr><td colspan="2">Response: When scaling generation, you are not simulating a contingency – you are just changing dispatch to simulate a transaction. The SDT does not see a conflict.</td></tr>
<tr><td>Electric Power Supply Association</td><td>The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose. We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency. The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to the document. Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization. In calculating the ATC or AFC as applicable, a significant factor in the calculations will be the assumed counterflows and postbacks. The standards provide no guidance on these terms, but rather leave them entirely to the discretion of the TSP, subject only to documentation of their assumptions in the ATCID, which might not be visible to market participants.</td></tr>
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| Entity | Comment |
|---|---|
| that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation. | |
| Florida Municipal Power Agency | Many small Transmission Operators are network service customers of, and are wholly enclosed by, a much larger TOP/TSP. They have no viable paths or customers in and of themselves and currently their neighboring TOP/TSP handles all of the ATC-related data and calculations mentioned in this standard. In its current draft, this standard puts the onus of calculating TTC squarely on them, when in fact they are not the most appropriate entity for this task. We would suggest changing the Applicability section of this standard (and related standards) to exclude TOP's who are wholly enclosed by a single other TOP, or allow them the choice of deferring to the larger TOP's TTC calculations. We also believe that this standard needs an additional commenting period. |
| Response: The Drafting Team has modified the definition of ATC path, which may address some of your concerns. Additionally, Transmission Operators may delegate tasks to other parties. | |
| PPL Generation LLC | Confirmed TSR's affect non-firm ATC rather than schedules affecting Non-firm ATC. |
| Response: Confirmed firm TSR's affect Non-firm ATC and unscheduled firm TSR's affect non-firm ATC consistent with postback processes being developed by NAESB. | |
| PSEG Power LLC | PSEG Power LLC votes no for the reasons expressed in PJM's comments. |
| Response: Please see PJM response. | |
| Barry Green Consulting Inc. | Transparency: The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the standard that is being balloted, the word "transparency" has been deleted from the purpose. We also note that a requirement that sufficient data be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency. The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to the document.<br><br>Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization. In calculating the ATC or AFC as applicable, a significant factor in the calculations will be the assumed counterflows and postbacks. The standards provide no guidance on these terms, but rather leave them entirely to the discretion of the TSP, subject only to documentation of their assumptions in the ATCID. We would be concerned if these values are unduly conservative. |
| Response: NAESB is responsible for determining which information will be shared with market participants. While the standard does promote enhanced transparency, the purpose has been reworded to focus more on the reliability aspects of the standard. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation. | |
| Consolidated Edison Co. of New York | R2 applies to TOP but R2.1 refers to RC, R2.1 should address TOP. |
| Response: R2 and all of its sub-requirements specify how the Transmission Operator will model the Transmission Operator's Reliability | |

| Entity | Comment |
|---|---|
| Coordinator area and adjacent Reliability Coordinator areas. There is no action for the Reliability Coordinator in R2; R2.1 intends to covers the Reliability Coordinator's area for modeling purposes by the Transmission Operator, not the RC. The drafting team does not believe any change is necessary. | |
| MidAmerican Energy Co. | Although this standard leaves much to be desired, it is better than the current standard. I hope NERC continues to work towards consistency in the arena of transfer capability. |
| Response: Thank you for your comment, the drafting team will continue its work in developing reliability standards. | |
| PP&L, Inc. | Confirmed TSR's affect non-firm ATC rather than schedules affecting Non-firm ATC. |
| Response: Confirmed firm TSR's affect Non-firm ATC and unscheduled firm TSR's affect non-firm ATC consistent with postback processes being developed by NAESB. | |
| PSEG Energy Resources & Trade LLC | PSEG Energy Resources & Trade votes NO for the reasons expressed by PJM in its ballot. |
| Response: Please see PJM response. | |
| Commonwealth of Massachusetts Department of Public Utilities | The Massachusetts DPU would like a clarification as to why "161kV or below" was chosen in section R2.1 for being the threshold for allowing equivalent representation of radial lines and facilities. |
| Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The specification of 161 kV doesn't preclude using a lower threshold for equivalencing if desired. | |
| Wyoming Public Service Commission | [i] Nothing in this Methodology should prevent the use of diversity interchange (such as ADI) to improve overall grid efficiency. [ii] In R6.3, remove the words "in duration" from the end of the sentence, viz: "provided such outage is expected to last 24 hours or longer in duration." "In duration" is redundant. |
| Response: The Drafting Team does not believe the standard prohibits the use of ACE Diversity Interchange (ADI) or similar enhancements. If Wyoming Public Service Commission believes otherwise, please detail the potential conflicts in future comments.<br>The Drafting Team has removed the redundant language as suggested. | |
| Midwest Reliability Organization | The MRO does not support this standard. Certain MRO members have concerns with the application of the standard for transmission providers that use flowgates. |
| Response: The SDT does not understand the concern expressed. This standard would not apply to entities that elected to use the flowgate methodology. We do not believe there is any conflict between methodologies. | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30 Day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Transmission Reliability Margin Implementation Document (TRMID):** A document that describes the implementation of a Transmission Reliability Margin methodology.

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**
2. **Number:** **MOD-008-1**
3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.
4. **Applicability:**
   **4.1.** Transmission Operator.
   **4.2.** Transmission Service Provider.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in calculating TRM, and a description of how that component is used to calculate a TRM value:

- Aggregate Load forecast uncertainty (not included in determining generation reliability requirements for CBM).
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve sharing requirements.
- Inertial response and frequency bias.

**R1.2.** A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in the Transmission planning process for the time period studied .

**R1.3.** The description of the method used to allocate TRM across ATC Paths or Flowgates.

**R1.4.** The identification of the TRM calculation used for the following time periods:

**R1.4.1.** Same day and real-time.

**R1.4.2.** Day-ahead and pre-schedule.

**R1.4.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

**R1.5.** If TRM is not used, a statement of that practice.

**R2.** Each Transmission Operator shall only use the components of uncertainty from R1.1 to calculate TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.** Each Transmission Operator shall make available its TRMID, and any underlying documentation, work papers and load flow base cases used to determine TRM, to any of the following who make a written request no more than 30 calendar days after receiving the request. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Operators

**R4.** Each Transmission Operator using TRM shall recalculate TRM values in accordance with the TRMID at least once every 13 months. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R5.** The Transmission Operator using TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after they change. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

## C. Measures

**M1.** Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, and CBMID , or other evidence, (such as written documentation, study reports, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** Each Transmission Operator shall provide a dated copy of any request for its TRMID or associated documentation, and evidence such as copies of emails or postal receipts that show the recipient, date and contents as evidence that the requested documentation was provided within the specified timeframe to the entities described in R3. (R3)

**M4.** Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it recalculated TRM values at least once every thirteen months for each of the TRM time periods. (R4)

**M5.** Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago. | The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.<br>**OR**<br>The Transmission Operator's TRMID does not address one of the sub requirements. | The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.<br>**OR**<br>The Transmission Operator's TRMID does not address two or three of the sub requirements. | The Transmission Operator has a TRMID that does not incorporate changes that have been made more than one year ago.<br>**OR**<br>The Transmission Operator does not have a TRMID;<br>**OR**<br>The Transmission Operator's TRMID does not address 4 or more of the sub requirements. |
| R2. | N/A | N/A | N/A | The Transmission Operator included elements of uncertainty not defined in R1 in their calculation of TRM.<br>**OR**<br>The Transmission Operator included components of CBM in TRM. |
| R3. | The Transmission Operator provided the TRMID to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days. | The Transmission Operator provided the TRMID to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days. | The Transmission Operator provided the TRMID to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days. | The Transmission Operator did not provide the TRMID for 90 days or more. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R4 | N/A | The Transmission Operator did not determine TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago. | The Transmission Operator determined TRM 15 months ago or more, but not more than 18 months ago. | The Transmission Operator did not determine TRM<br>OR<br>The last determination of TRM was 18 months ago or more. |
| R5 | The Transmission Operator did provide the TRM to all entities specified in more then 7 days but less than 14 days. . | The Transmission Operator did provide the TRM to all entities specified in 14 days or more, but less than 30 days. | The Transmission Operator did provide the TRM to all entities specified in 30 days or more, but less than 60 days. | The Transmission Operator did not provide the TRM to all entities specified within 60 days of the change. |

## Standard Development Roadmap

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2. **Number:** **MOD-008-1**

3. **Purpose:** To promote the consistent and ~~transparent~~ reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to ~~ensure~~ support ~~reliable~~ analysis and system operations.

4. **Applicability:**

   **4.1.** Transmission Operator.

   **4.2.** Transmission Service Provider.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date ~~that all six (MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, MOD-030-1)ATC-related standards are~~this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date th~~e set of~~is standard~~s~~ is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** Identification of (on each of its respective ~~Posted~~ ATC Paths or Flowgates) each of the following components of uncertainty if used in calculating TRM, and a description of how that component is used to calculate a TRM value:

- Aggregate Load forecast uncertainty (not included in determining generation reliability requirements for CBM).
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- Reserve sharing requirements.
- Inertial response and frequency bias.

**R1.2.** A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in ~~any associated~~

~~operations studies or~~the Transmission planning ~~studies~~process for the ~~corresponding~~ time period studied .

~~**R1.2.**periods.~~

**R1.3.** The description of the method used to allocate~~of~~ TRM ~~allocation~~ across ATC~~Posted~~ Paths or Flowgates.

**R1.4.** The identification of the TRM calculation used for the following time periods:

**R1.4.1.** Same day and real-time.

**R1.4.2.** Day-ahead and pre-schedule.

**R1.4.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

**R1.5.** If TRM is not used, ~~zero for all the time periods listed in R1.4,~~ a statement of that practice.

**R2.** ~~The~~ Each Transmission Operator shall only use the components of uncertainty from R1.1 to calculate TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. ~~Transmission capacity required for the period immediately following a contingency and up to 59 minutes following the contingency is included in TRM.~~ [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.** Each Transmission Operator shall make available ~~provide~~ its TRMID, and any underlying documentation, work papers and load flow base cases used to determine TRM, to any~~all~~ of the following who make a written ~~within seven calendar days of a~~ request no more than 30 calendar days after receiving the request. ~~:~~ [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- ~~The Transmission Service Provider responsible for tariff administration over the Facilities operated by the Transmission Operator~~
- ~~The Reliability Coordinator responsible for oversight of the Facilities for which the Transmission Service Provider offers service.~~
- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Operators

~~**R4.**Each Transmission Service Provider shall make available within seven calendar days of a documented request for such information the TRMIDs used by its Transmission Operator(s), and any underlying documentation, work papers and load flow base cases used to determine TRM, to Transmission Service Providers who have made a request for such information. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]~~

~~**R5.** Each Transmission Operator shall calculate, at least once every 13 months (in accordance with the definitions in its TRMID), a TRM value for the following time periods (on each Posted Path or Flowgate) and shall provide these TRM values to its Transmission Service Provider(s) and Transmission Planner(s) within seven calendar~~

~~days of the calculation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]~~

~~**R5.1.**R4.1 Same day and real-time.~~

~~**R5.2.**R4.2 Day-ahead and pre-schedule.~~

**R4.** Each Transmission Operator using TRM shall recalculate TRM values in accordance with the TRMID at least once every 13 months. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R5.** The Transmission Operator using TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after the~~ir~~y changing~~e~~. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

## C. Measures

**M1.** Each~~The~~ Transmission ~~Service Provider~~Operator shall produce its ~~current~~ TRMID evidencing inclusion of all specified information ~~described~~ in ~~R1to show its compliance with~~ R1. ~~.~~(R1)

**M2.** ~~The~~ Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, and CBMID , or other evidence, (such as written documentation, study reports, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** ~~The~~ Each Transmission Operator shall provide a dated copy of any request for its TRMID or associated documentation, and evidence such as copies of emails or postal receipts that show the recipient, date and contents as evidence that the requested documentation was provided within the specified timeframe to the entities described in R3. (R3)

~~**M4.**The Transmission Service Provider shall provide a dated copy of any request for its Transmission Operator's TRMID or associated documentation, and evidence such as copies of emails or postal receipts that show the recipient, date and contents as evidence that the requested documentation was provided within the specified timeframe to the requesting entity as described in R4. (R4)~~

~~**M5.**The Transmission Operator shall provide evidence (such as logs and data that it determined TRM at least once every thirteen months for each of the listed time periods and provided it to their Transmission Service Provider(s) and Transmission Planner(s) as described in R5. (R5)~~

**M4.** ~~The~~Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it recalculated TRM values at least once every thirteen months for each of the TRM time periods. (R4)

**M5.** ~~The~~Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago. | The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.<br>**OR**<br>The Transmission Operator's TRMID does not address one of the sub requirements. | The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.<br>**OR**<br>The Transmission Operator's TRMID does not address two or three of the sub requirements. | The Transmission Operator has a TRMID that does not incorporate changes that have been made more than one year ago.<br>**OR**<br>The Transmission Operator does not have a TRMID;<br>**OR**<br>The Transmission Operator's TRMID does not address 4 or more of the sub requirements. |
| R2. | N/A | N/A | N/A | The Transmission Operator included elements of uncertainty not defined in R1 in their calculation of TRM.<br>**OR**<br>The Transmission Operator ~~or it~~ included components of CBM in TRM. |
| R3. | The Transmission Operator ~~did~~ provided the TRMID to ~~all~~ a requesting ~~entities~~ entity specified in R3 but provided TRMID ~~to all parties~~ in more than ~~7~~30 days but less than ~~14?~~45 days. ~~.~~ | The Transmission Operator provided the TRMID to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days. ~~The Transmission Operator did not provide the TRMID to one entities specified in R3~~<br>~~**OR**~~ | The Transmission Operator provided the TRMID to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days. ~~The Transmission Operator did not provide the TRMID to two entities specified in R3~~<br>~~**OR**~~ | The Transmission Operator did not provide the TRMID for 90 days or more. ~~The Transmission Operator did not provide the TRMID to any of the entities specified in R3~~<br>~~**OR**~~<br>~~provided TRMID to all parties in more than 60 days.~~<br>~~Failed to provide the TRMID~~ |

| | | | | | |
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| | | | ~~provided TRMID to all parties in more than 14~~ ? ~~days or more but less than~~ ?~~30 days. .~~ | ~~provided TRMID to all parties in more than 30~~ ? ~~days or more but less than~~ ?~~60 days.~~ | ~~within ? Days.~~ |
| | ~~R4.~~<br>~~R5~~<br>R4 | ~~The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in more than 7 calendar days but no more than 14 days of a request by a Transmission Service Provider.~~<br><br>~~The Transmission Operator did not provide the Transmission Planner with its determined TRM values.~~<br><br>N/A | ~~The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in more than 14 calendar days but no more than 30 days of a request by a Transmission Service Provider.~~<br><br>~~The Transmission Operator did not determine TRM for any of the listed time frames within thirteen months of the previous determination, and the last determination was not more than 15 months ago.~~<br><br>The Transmission Operator did not determine TRM ~~for any of the listed time frames~~ within thirteen months of the previous determination, and the last determination was not more than 15 months ago. | ~~The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in more than 30 calendar days but no more than 60 days of a request by a Transmission Service Provider.~~<br><br>~~The Transmission Operator did not determine TRM for any of the listed time frames within thirteen months of the previous determination, and the last determination was more than 15 months ago, but not more than 18 months ago.~~<br><br>~~**OR**~~<br><br>~~The Transmission Operator did not provide the Transmission Service Provider with its determined TRM values, and one or more of those values changed by more than twenty percent from the previous value given to the Transmission Service Provider.~~<br><br>The Transmission Operator ~~did not~~ determined TRM ~~for any of the listed time frames within thirteen months of the previous~~ | ~~The Transmission Service Provider made available the current TRMID and supporting documentation as specified in R4 in 60 days or more of a request by a Transmission Service Provider Or did not make the current TRMID available.~~<br><br>~~The Transmission Operator did not determine TRM for any of the listed time frames within thirteen months of the previous determination, and the last determination was more than 18 months ago.~~<br><br>~~**OR**~~<br><br>~~The Transmission Operator has not provided the Transmission Service Provider with any determined TRM values.~~<br><br>The Transmission Operator did not determine TRM<br><br>OR~~for any of the listed time frames within thirteen months of the previous determination,~~<br><br>~~and t~~The last determination of TRM was ~~more than~~ 18 months |

| | | | | |
|---|---|---|---|---|
| | | | ~~determination, and the last determination was more than~~ 15 months ago or more, but not more than 18 months ago. | ago or more. |
| R5 | The Transmission Operator did provide the TRM to all entities specified in more then 7 days but less than 14 days. . | The Transmission Operator did provide the TRM to all entities specified in 14 days or more, but less than 30 days. | The Transmission Operator did provide the TRM to all entities specified in 30 days or more, but less than 60 days. | The Transmission Operator did not provide the TRM to all entities specified within 60 days of the change. |

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# Implementation Plan for Standard MOD-008-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-008-1, which describes the reliability aspects of determining and maintaining a Transmission Reliability Margin and what components of uncertainty may be considered when making that determination.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes MOD-008-1. MOD-009-0 has been incorporated into this standard, made irrelevant by this standard, or is being addressed by the North American Energy Standards Board, and should be retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-008-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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## Summary Consideration of Comments:

The Drafting Team has reviewed the comments and made some changes to the standard to address these comments.

1. The Drafting Team changed the language to specify the TRM be “established” instead of “calculated” in requirement 4 and all subsequent references to the number.

2. The drafting team removed the requirement that the assumptions used in Transmission Reliability Margin studies be consistent with those used in "associated" operations or planning studies. Studies used for TRM are based on non-standard scenarios, and would be inappropriate to make consistent with “normal” studies.

3. All VRFs were set to “Lower” in response to industry comments. A medium risk factor is appropriate for “a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures.” A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator’s existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.

4. A more graded approach was applied to the VSLs where appropriate.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/standards/newstandardsprocess.html.

| Entity | Comment |
|---|---|
| Associated Electric Cooperative, Inc. | AECI does not understand why there can not be an option to continue to use the conservative 5% option that the NERC white paper dated 7/14/1999 suggest is reasonable. It takes a lot of effort to provide the document being requested for TRM. If we are currently using the rule of thumb method (i.e. 5%) this should be and option. If an entity want to go less than 5% the entity should provide all the basis for the justification as noted in the standard. The VSLs are also high. |
| Response: The standard does allow the use of 5%, but requires an explanation of what the percentage represents. In addition the Drafting Team added language to Requirement 3 to be clear that entities only have to provide information that was used, not create information to support a request. Members of the Drafting Team reviewed the white paper referenced and other resources and do not, at this time, have sufficient technical information to establish a default or recommended TRM that would adequately balance reliability and market availability for all parts of North America.<br>The Drafting Team has redrafted the VSLs to include more gradation criteria | |
| CenterPoint Energy | ERCOT's filed comments to the SDT that ATC, TTC, CBM, and TRM are not applicable within ERCOT operations and that these Standards should have provisions that make it clear that these requirements apply only within market structures in which they are pertinent were ignored by the SDT. These standards should not apply to ERCOT, thus our negative vote. |
| MOD-008 only applies to Transmission Operators that maintain TRM. | |
| FirstEnergy Energy Delivery | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br>CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc.<br>FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both.<br>Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td></td><td>FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives. FirstEnergy Corp.<br>Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment.<br><br>(FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>– For utilities involved in market structures, the Transmission Service Provider (TSP) is ultimately responsible for calculating and assuring proper ATC for its footprint. Therefore in these instances it would not be appropriate that the Transmission Operator (TOP) be responsible for maintaining a TRMID. For example, in the MISO footprint, MISO maintains and implements a single TRMID for all of its member companies. The standard should reflect these alternative industry situations through either changes in the requirements or addition of market or regional variances specifically stated in the standard.<br>– Additionally, per MOD-004 R1, the TSP is responsible for maintaining a CBMID, and then it should follow that the TSP and not the TOP would be responsible for maintaining a TRMID.<br>Response: In order for the standard to be audited one entity alone must be accountable for a requirement. In the case of TRM the team decided for two reasons to assign this to the Transmission Operator. The first reason was the Transmission Operator is the ultimate customer of this value since the Transmission Operator is the one who has deal with the results of the TRM selection. The second is that the Transmission Operator is the lowest entity in the hierarchy, and in some cases the Transmission Operator may not wish to relegate this authority to someone else, and by not assigning it to them the team would have limited their options in that regard. Ultimately the team believes that in cases where TRM is used, the Transmission Operator is responsible for either developing the TRM or insuring that it is developed. Nothing in the standard prevents the Transmission Operator from contracting the responsibility and accepting another parties TRMID and TRM values.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Great River Energy</td><td>GRE agrees with the PJM and MISO recommendation that the standard needs an additional commenting period based on the significance of the comments submitted during the previous commenting periods.</td></tr>
<tr><td colspan="2">Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment.</td></tr>
<tr><td>Hydro One Networks, Inc.</td><td>Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighbouring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory</td></tr>
</table>

| Entity | Comment |
|---|---|
| | approval in not required that is, only when all regulatory approvals have been obtained, |
| Response: The Drafting Team does not believe this standard must be implemented at the same time throughout North America. | |
| Kansas City Power & Light Co. | Requirements state that the Transmission Operator is to perform functions that are currently performed by the SPP Transmission Service Provider for KCPL. Suggest revising requirements by adding "or Transmission Service Provider" after "Transmission Operator" so that either entity could perform these tasks. |
| Response: In order for the standard to be audited one entity alone must be accountable for a requirement. In the case of TRM the team decided for two reasons to assign this to the Transmission Operator. The first reason was the Transmission Operator is the ultimate customer of this value since the Transmission Operator is the one who has deal with the results of the TRM selection. The second is that the Transmission Operator is the lowest entity in the hierarchy, and in some cases the Transmission Operator may not wish to relegate this authority to someone else, and by not assigning it to them the team would have limited their options in that regard. Ultimately the team believes that in cases where TRM is used, the Transmission Operator is responsible for either developing the TRM or insuring that it is developed. Nothing in the standard prevents the Transmission Operator from contracting the responsibility and accepting another parties TRMID and TRM values. | |
| Potomac Electric Power Co. | Potomac Electric agrees with the comments of PJM distributed to the ballot body. I will not repeat them here, but do include the headings:<br>I. The ATC MOD standards should have been sent out for comment not pre-ballot posting.<br>II. Depth of the ATC MOD standards is excessive.<br>III. Determining Violation Risk Factors is incorrect. I<br>IV. Determining Violation Severity Levels is incomplete. |
| Response: Please see response to PJM. | |
| Public Service Electric and Gas Co. | PSE&G votes NO for the reasons expressed in PJM's comments. |
| Response: Please see response to PJM. | |
| Southern Company Services, Inc. | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: Thank you for your support. However, based on industry response, the drafting team has made modifications to the standard and is reposting for another comment period. | |
| Westar Energy | Should also apply to Transmission Planners and Planning Authorities |
| Response: The TRM value is developed by the Transmission Operator so there are no requirements placed on the Transmission Planner or Planning Coordinator, and therefore they are not listed in the applicability section. As part of the review regarding your comment, the Drafting Team removed the Transmission Service Provider since they no longer have requirements under MOD 008. The team extensively discussed | |

| Entity | Comment |
|---|---|
| adding a new requirement addressing the Transmission Planner and Planning Coordinator; however the drafting team determined that they could not draft language to tie the TRM to operational and planning studies without essentially creating another planning or operational planning standard in addition to the existing one. From a reliability perspective, if the entity is meeting the operational and planning requirements then they are by definition planning a reliable system regardless of their inclusion or exclusion of TRM from those studies. If an entity is using an overly restrictive TRM or using a TRM that is inconsistent with their planning practices this is a commercial or hoarding issue, and not a transmission reliability issue (which is the focus of NERC standards). Additionally, since TRM is based on studies that go beyond the "normal" operations of the system, the drafting team felt it would be inappropriate to require these "what if" scenarios to be limited by those studies used in normal operations planning. | |
| New York Independent System Operator | The NYISO agrees with PJM that:<br>– the assumptions used in Transmission Reliability Margin studies need not necessarily be consistent with those used in "associated" operations or planning studies and that R1 should be modified accordingly (including to clarify what counts as an "associated" study;<br>Response: The drafting team has eliminated this requirement from the standard.<br><br>– R3 should allow a default percentage to be used without requiring underlying documentation, work papers, or load flow base cases if they are not used to determine that percentage;<br>Response: Nothing in the standard precludes the use of a percentage. Although the standard does require an explanation of what the percentage represents, it no longer explicitly requires any specific underlying documentation.<br><br>– revised requirements R4 and R5 are overly prescriptive,<br>– establish TRM recalculation frequency requirements that should be left to NAESB,<br>– and have been assigned an inappropriately severe violation risk factor that (Medium) that is not consistent with NERC's own rules on defining risk factors; and<br>– revised R5's proposed violation severity levels that do not recognize that there may be differing level of non-compliance.<br>– The NYISO is also concerned that revised requirement R4 would require TRM to be recalculated more frequently than necessary for Transmission Operators whose TRM assumptions do not change frequently. At a minimum, the NYISO requests that the SDT modify R4 in the same way that MOD-001 requirement R7 was revised, i.e., so that TRM need not be recalculated every 13 months to the extent that none of the underlying inputs change.<br>Response: The Drafting Team changed the language to specify "establishing" of the TRM values once every 13 months. The change to "establish" was made to emphasize that simply affirming the current value should continue to be used is sufficient for compliance. The Drafting Team believes that this is appropriate to be assigned to NERC. The team has moved all the violation risk factors to low, and has redrafted the VSLs to include more gradation criteria. The team has determined that if entities are using these values to allow transactions, then the ATC value (including its components such as TRM) is important to reliability. |
| Response: Please see in-line responses. | |

| Entity | Comment |
| --- | --- |
| PJM Interconnection, L.L.C. | MOD-008 Specific Comments:<br>PJM believes no requirement from the set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and<br>(a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or<br>(b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. The ATC MOD standards should have been sent out for comment not pre-ballot posting.<br>Response: The Drafting Team in response to the industry comments has set the VRF's to lower for all requirements. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br><br>Requirement 1<br>– R1.2 requires the use of assumptions consistent with those used in the Transmission planning process, while MOD-001 R6 requires the use of assumptions consistent with those used in associated operations studies or planning studies. This difference needs to be clarified and consistent among all the MOD standards where applicable. PJM believes that the language should be modified because there are many studies that are performed within the different Functions and can serve different purposes. Therefore, ATC calculations assumptions need not be consistent with this diverse array of studies.<br>– The phrase "associated studies" can be ambiguous and subject to interpretation without more clarity. PJM proposes that TRM standards follow the same type exclusion as mentioned for MOD-001 R6: TRM assumptions need not be consistent with assumptions used in Transmission planning process not associated with calculating TTC, AFC, and ATC.<br>Response: The Drafting Team has eliminated R1.2.<br><br>Requirement 3<br>– R3 should allow a default percentage to be used without requiring specific documentation, work papers and load flow cases if a straight percentage like 5% is used. Additional information would be required only if a greater |

| Entity | Comment |
|---|---|
| | amount is used. This requirement is burdensome for a component of ATC that should be easy to assess its reasonableness.<br>Response: The standard does allow the use of 5%, but requires an explanation of what the percentage represents. In addition the Drafting Team added language to Requirement 3 to be clear that entities only have to provide information that was used, not create information to support a request. Members of the Drafting Team reviewed the white paper referenced by AECI and other resources and do not, at this time, have sufficient technical information to establish a default or recommended TRM that would adequately balance reliability and market availability for all parts of North America.<br><br>Requirement 4<br>– R4 is NAESB scope because the requirements address timeframes to provide information and the frequency of recalculation. These requirements at best are minor requirements that will not affect reliability because a TSP can assign a reasonable TRM per R1.2 whether they own the facilities or not and the TRM changes infrequently. These reasons indicate that the requirements should not have a Violation Risk factor of Medium but should not even be requirements.<br>Response: The Drafting Team changed the language to specify "establishing" of the TRM values once every 13 months. The change to "establish" was made to emphasize that simply affirming the current value should continue to be used is sufficient for compliance. The team has moved all the violation risk factors to low. The team has determined that if entities are using these values to allow transactions, then the ATC value (including its components such as TRM) is important to reliability.<br><br>– The "Medium" risk factor is inconsistent with NERC's definition of risk factors and should be changed to "Lower" if the requirement is to be retained.<br>Response: The Drafting Team has modified this risk factor to Lower in response to industry concerns.<br><br>Requirement 5<br>– The "Medium" risk factor is inconsistent with NERC's definition of risk factors and should be changed to "Lower" if the requirement is to be retained.<br>Response: The Drafting Team has modified this risk factor to Lower in response to industry concerns.<br><br>– R5, the measure M5, and the Violation Severity Level should be graded to include the number of facilities or flowgates not provided. Example is if the TSP missed providing TRM information to a requestor on one of the 300 coordinated flowgates and the requestor didn't spot it, but an auditor did 90 days later it is a severe reliability threatening violation. If 5 flowgates were missed that could be considered five separate severe violations for something that can be assigned by TSP for their process, but not easy to determine if the value they used was actually provided by the flowgate owner TSP.<br>Response: The drafting team has modified the VSLs to be more graded. |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td>Alabama Power Company</td><td>We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team.</td></tr>
<tr><td colspan="2">Response: Thank you for your support. However, based on industry response, the drafting team has made modifications to the standard and is reposting for another comment period.</td></tr>
<tr><td>American Electric Power</td><td>By definition TRM is a margin based largely upon the confidence in the accuracy of the calculation process for ATC, therefore its more of a TSP function that any other entity. Since TRM is an input to ATC determination, and not used in Operation of the system, the responsibility is misplaced. delegation of this 'responsibility' is not appropriate because TRM is not used in real time operation.<br>Response: In order for the standard to be audited one entity alone must be accountable for a requirement. In the case of TRM the team decided for two reasons to assign this to the Transmission Operator. The first reason was the Transmission Operator is the ultimate customer of this value since the Transmission Operator is the one who has deal with the results of the TRM selection. The second is that the Transmission Operator is the lowest entity in the hierarchy, and in some cases the Transmission Operator may not wish to relegate this authority to someone else, and by not assigning it to them the team would have limited their options in that regard. Ultimately the team believes that in cases where TRM is used, the Transmission Operator is responsible for either developing the TRM or insuring that it is developed. Nothing in the standard prevents the Transmission Operator from contracting the responsibility and accepting another parties TRMID and TRM values.<br><br>There must also be an exclusion for those partiers that do not calculate ATC -- such as ERCOT, NEISO, AEP (we are a TOP in SPP and PJM)<br>Response: The TRM standard applicability has been modified to apply only to those entities that have elected to maintain a TRM.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Dominion Resources, Inc.</td><td>In support of PJM comments</td></tr>
<tr><td colspan="2">Response: Please see response to PJM.</td></tr>
<tr><td>FirstEnergy Solutions</td><td>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br>CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc.<br>FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be</td></tr>
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| Entity | Comment |
|---|---|
| | used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both.<br>Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br>Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment.<br><br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>– For utilities involved in market structures, the Transmission Service Provider (TSP) is ultimately responsible for calculating and assuring proper ATC for its footprint. Therefore in these instances it would not be appropriate that the Transmission Operator (TOP) be responsible for maintaining a TRMID. For example, in the MISO footprint, MISO maintains and implements a single TRMID for all of its member companies. The standard should reflect these alternative industry situations through either changes in the requirements or addition of market or regional variances specifically stated in the standard.<br>– Additionally, per MOD-004 R1, the TSP is responsible for maintaining a CBMID, and then it should follow that the TSP and not the TOP would be responsible for maintaining a TRMID.<br>Response: In order for the standard to be audited one entity alone must be accountable for a requirement. In the case of TRM the team decided for two reasons to assign this to the Transmission Operator. The first reason was the Transmission Operator is the ultimate customer of this value since the Transmission Operator is the one who has deal with the results of the TRM selection. The second is that the Transmission Operator is the lowest entity in the hierarchy, and in some cases the Transmission Operator may not wish to relegate this authority to someone else, and by not assigning it to them the team would have limited their options in that regard. Ultimately the team believes that in cases where TRM is used, the Transmission Operator is responsible for either developing the TRM or insuring that it is developed. Nothing in the standard prevents the Transmission Operator from contracting the responsibility and accepting another parties TRMID and TRM values. |
| Response: Please see in-line responses. | |

| Entity | Comment |
|---|---|
| Florida Municipal Power Agency | We believe this standard needs an additional commenting period. |
| | Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment. |
| Georgia Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| | Response: Thank you for your support. However, based on industry response, the drafting team has made modifications to the standard and is reposting for another comment period. |
| Gulf Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| | Response: Thank you for your support. However, based on industry response, the drafting team has made modifications to the standard and is reposting for another comment period. |
| Hydro One Networks, Inc. | Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighbouring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained. |
| | Response: The Drafting Team does not believe this standard must be implemented at the same time throughout North America. |
| Lincoln Electric System | LES agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| | Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment. |
| MidAmerican Energy Co. | I agree with the PJM recommendation that the standard needs an additional commenting period. |
| | Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment. |
| Mississippi Power | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| | Response: Thank you for your support. However, based on industry response, the drafting team has made modifications to the standard and is reposting for another comment period. |

| Entity | Comment |
| --- | --- |
| Orlando Utilities Commission | This standard should contain only 'lower' level VRF's. |
| Response: The drafting team has modified the VRFs to be Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling. | |
| Public Service Electric and Gas Co. | PSE&G votes NO for the reasons expressed in PJM's comments. |
| Response: Please see response to PJM. | |
| Wisconsin Public Service Corp. | WPSC agrees with the PJM and MISO recommendation that the standard needs an additional commenting period |
| Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment. | |
| Florida Municipal Power Agency | We believe this standard needs an additional commenting period. |
| Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment. | |
| Madison Gas and Electric Co. | We agree with the PJM and MISO recommendation that the standard needs an additional commenting period . |
| Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment. | |
| WPS Resources Corp. | Need to include a definition of "TRM".<br>Response: TRM is defined in the NERC glossary of terms: "Transmission Reliability Margin (TRM) — That amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. See Available Transfer Capability."<br><br>R3 - the TRM implementation document (TRMID) should be made available to all users, owners, and operators.<br>Response: R3 applies to the entities that may have a reliability need to review the material, access to the material by others would be established through other processes, for example NAESB. |

| Entity | Comment |
|---|---|
| | R1.1 - a subsection of R1.1 refers to CBM and "generation reliability requirements". CBM should be tied to "resource adequacy assessment requirements".<br>Response: The drafting team revised the wording to remove descriptors beyond CBM. |
| Response: Please see in-line responses. | |
| AEP Service Corp. | By definition TRM is a margin based largely upon the confidence in the accuracy of the calculation process for ATC, therefore its more of a TSP function that any other entity. Since TRM is an input to ATC determination, and not used in Operation of the system, the responsibility is misplaced. delegation of this 'responsibility' is not appropriate because TRM is not used in real time operation.<br>Response: In order for the standard to be audited one entity alone must be accountable for a requirement. In the case of TRM the team decided for two reasons to assign this to the Transmission Operator. The first reason was the Transmission Operator is the ultimate customer of this value since the Transmission Operator is the one who has deal with the results of the TRM selection. The second is that the Transmission Operator is the lowest entity in the hierarchy, and in some cases the Transmission Operator may not wish to relegate this authority to someone else, and by not assigning it to them the team would have limited their options in that regard. Ultimately the team believes that in cases where TRM is used, the Transmission Operator is responsible for either developing the TRM or insuring that it is developed. Nothing in the standard prevents the Transmission Operator from contracting the responsibility and accepting another parties TRMID and TRM values.<br><br>There must also be an exclusion for those partiers that do not calculate ATC -- such as ERCOT, NEISO, AEP (we are a TOP in SPP and PJM)<br>Response: The TRM standard applicability has been modified to apply only to those entities that have elected to maintain a TRM. |
| Response: Please see in-line responses. | |
| Calpine Corporation | The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose.<br>We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency.<br>The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document, is difficult to evaluate if it is not yet determined which parties will have access to the document. |

| Entity | Comment |
|---|---|
| | Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization. |
| Response: These comments are related to the MOD 001 standard and not to the MOD 008 TRM standard; therefore the Drafting Team will not provide a specific response here. | |
| Electric Power Supply Association | EPSA supports the use of a TRMID document as a positive step toward greater transparency. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the ultimate use of such a document, cannot be evaluated if the document access has not been clarified.<br>Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the TRMID cannot assure market participants of a sufficient degree of standardization. |
| Response: R3 applies to the entities that may have a reliability need to review the material, access to the material by others would be established through other processes, for example NAESB.<br>We recognize that at this time, the standard is more flexible than might be desired, and will recommend that NERC do additional work after the transparency issues have been addressed. Members of the Drafting Team do not, at this time, have sufficient technical information to establish a default or recommended TRM that would adequately balance reliability and market availability for all parts of North America. | |
| FirstEnergy Solutions | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br>CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc.<br>FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both.<br>Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will |

| Entity | Comment |
|---|---|
| | now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br>Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment.<br><br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>– For utilities involved in market structures, the Transmission Service Provider (TSP) is ultimately responsible for calculating and assuring proper ATC for its footprint. Therefore in these instances it would not be appropriate that the Transmission Operator (TOP) be responsible for maintaining a TRMID. For example, in the MISO footprint, MISO maintains and implements a single TRMID for all of its member companies. The standard should reflect these alternative industry situations through either changes in the requirements or addition of market or regional variances specifically stated in the standard.<br>– Additionally, per MOD-004 R1, the TSP is responsible for maintaining a CBMID, and then it should follow that the TSP and not the TOP would be responsible for maintaining a TRMID.<br>Response: In order for the standard to be audited one entity alone must be accountable for a requirement. In the case of TRM the team decided for two reasons to assign this to the Transmission Operator. The first reason was the Transmission Operator is the ultimate customer of this value since the Transmission Operator is the one who has deal with the results of the TRM selection. The second is that the Transmission Operator is the lowest entity in the hierarchy, and in some cases the Transmission Operator may not wish to relegate this authority to someone else, and by not assigning it to them the team would have limited their options in that regard. Ultimately the team believes that in cases where TRM is used, the Transmission Operator is responsible for either developing the TRM or insuring that it is developed. Nothing in the standard prevents the Transmission Operator from contracting the responsibility and accepting another parties TRMID and TRM values. |
| Response: Please see in-line responses. | |
| Florida Municipal Power Agency | We believe this standard needs an additional commenting period. |
| Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment. | |
| Lincoln Electric System | LES agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment. | |
| PSEG Power LLC | PSEG Power LLC votes no for the reasons expressed in PJM's comments. |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td colspan="2">Response: Please see response to PJM.</td></tr>
<tr><td>AEP Marketing</td><td>By definition TRM is a margin based largely upon the confidence in the accuracy of the calculation process for ATC, therefore its more of a TSP function that any other entity. Since TRM is an input to ATC determination, and not used in Operation of the system, the responsibility is misplaced. delegation of this 'responsibility' is not appropriate because TRM is not used in real time operation.<br><br>Response: In order for the standard to be audited one entity alone must be accountable for a requirement. In the case of TRM the team decided for two reasons to assign this to the Transmission Operator. The first reason was the Transmission Operator is the ultimate customer of this value since the Transmission Operator is the one who has deal with the results of the TRM selection. The second is that the Transmission Operator is the lowest entity in the hierarchy, and in some cases the Transmission Operator may not wish to relegate this authority to someone else, and by not assigning it to them the team would have limited their options in that regard. Ultimately the team believes that in cases where TRM is used, the Transmission Operator is responsible for either developing the TRM or insuring that it is developed. Nothing in the standard prevents the Transmission Operator from contracting the responsibility and accepting another parties TRMID and TRM values.<br><br>There must also be an exclusion for those parties that do not calculate ATC -- such as ERCOT, NEISO, AEP (we are a TOP in SPP and PJM)<br><br>The TRM standard applicability has been modified to apply only to those entities that have elected to maintain a TRM.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Barry Green Consulting Inc.</td><td>Transparency: The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose.<br><br>We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency.<br><br>The notion of a TRMID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to the document.<br><br>Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the TRMID cannot assure market participants of a sufficient degree of standardization.</td></tr>
<tr><td colspan="2">Response: These comments are related to the MOD 001 standard and not to the MOD 008 TRM standard; therefore the Drafting Team will not provide a specific response here.</td></tr>
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| Entity | Comment |
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| We recognize that at this time, the standard is more flexible than might be desired, and will recommend that NERC do additional work after the transparency issues have been addressed. Members of the Drafting Team do not, at this time, have sufficient technical information to establish a default or recommended TRM that would adequately balance reliability and market availability for all parts of North America. | |
| Dominion Resources, Inc. | Support comments provided by PJM |
| Response: Please see response to PJM. | |
| FirstEnergy Solutions | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>– For utilities involved in market structures, the Transmission Service Provider (TSP) is ultimately responsible for calculating and assuring proper ATC for its footprint. Therefore in these instances it would not be appropriate that the Transmission Operator (TOP) be responsible for maintaining a TRMID. For example, in the MISO footprint, MISO maintains and implements a single TRMID for all of its member companies. The standard should reflect these alternative industry situations through either changes in the requirements or addition of market or regional variances specifically stated in the standard.<br>– Additionally, per MOD-004 R1, the TSP is responsible for maintaining a CBMID, and then it should follow that the TSP and not the TOP would be responsible for maintaining a TRMID. |
| Response: In order for the standard to be audited one entity alone must be accountable for a requirement. In the case of TRM the team decided for two reasons to assign this to the Transmission Operator. The first reason was the Transmission Operator is the ultimate customer of this value since the Transmission Operator is the one who has deal with the results of the TRM selection. The second is that the Transmission Operator is the lowest entity in the hierarchy, and in some cases the Transmission Operator may not wish to relegate this authority to someone else, and by not assigning it to them the team would have limited their options in that regard. Ultimately the team believes that in cases where TRM is used, the Transmission Operator is responsible for either developing the TRM or insuring that it is developed. Nothing in the standard prevents the Transmission Operator from contracting the responsibility and accepting another parties TRMID and TRM values. | |
| Lincoln Electric System | LES agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment. | |
| MidAmerican Energy Co. | Although this standard leaves much to be desired, it is better than the current standard. I hope NERC continues to work towards consistency in the arena of TRM. |
| Response: Thank you for your support. However, based on industry response, the drafting team has made modifications to the standard and is reposting for another comment period. | |
| PSEG Energy Resources & Trade LLC | PSEG Energy Resources & Trade LLC votes NO for the reasons expressed in PJM's ballot. |

| Entity | Comment |
|---|---|
| Response: Please see response to PJM. | |
| Wyoming Public Service Commission | Should not prevent the inclusion of intermittent resources if they exhibit sufficient diversity and can be successfully integrated. |
| Response: Nothing in the TRM standard prevents the inclusion of intermittent resources. | |
| Midwest Reliability Organization | The MRO agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The Drafting Team has withdrawn the standard from the balloting process and will be posting it again for industry comment. | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes the modifications with consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Generation Capability Import Requirement (GCIR):** The amount of generation capability from external sources requested by a Load-Serving Entity (LSE) (or group of LSEs with an aggregated need for Capacity Benefit Margin) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.

**Capacity Benefit Margin Implementation Document (CBMID):** A document that describes the implementation of a Capacity Benefit Margin methodology.

**Planned Resource Sharing Group (PRSG):** A group of Load-Serving Entities who have agreed to jointly meet their resource adequacy requirements.

## A. Introduction

1. **Title: Capacity Benefit Margin**

2. **Number: MOD-004-1**

3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.

4. **Applicability:**

   **4.1. Functional Entity:**

   **4.1.1** Load-Serving Entity.

   **4.1.2** Planned Resource Sharing Group.

   **4.1.3** Transmission Service Providers that maintain CBM.

   **4.1.4** Balancing Authority.

   **4.1.5** Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM.

5. **Facility Limitations/Specifications:**

   **5.1.** None.

6. **Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard become effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service Provider shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

**R1.1.** Its procedure for a Load-Serving Entity or Planned Resource Sharing Group within a Balancing Authority associated with the Transmission Service Provider to request the Generation Capability Import Requirement (GCIR) including the disposition and handling of deficient requests.

**R1.2.** Its procedure and assumptions for setting CBM for each ATC Path or Flowgate based on Load-Serving Entity or Planned Resource Sharing Group GCIR.

**R1.3.** Its procedure to request the use of Transfer Capability set aside as CBM.

**R1.4.** A statement of whether the Transmission Service Provider allows ATC or AFC to be less than zero due to CBM.

**R2.** The Transmission Service Provider shall make available its CBMID and any changes to the CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area prior to the effective date of a change. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.** A Load-Serving Entity or Planned Resource Sharing Group that wants Transfer Capability to be set aside in the form of CBM shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

**R3.1.** Submit an annual GCIR request to the Transmission Service Provider and Transmission Planner per the specifications in the CBMID that includes:

**R3.1.1.** The GCIR, specifying:

3.1.1.1. A monthly GCIR value for each month for the next 24 months. If monthly values are not a requirement as per the applicable reserve margin and resource adequacy requirements documented in R3.1.2, a yearly GCIR value for the current and following year will be sufficient .

3.1.1.2. An annual GCIR value for each subsequent year for each Balancing Authority or Posted Path not to exceed 10 years into the future.

3.1.1.3. The location of the load served by the GCIR (e.g., Balancing Authority, zones, markets …).

3.1.1.4. Assumed external resources (e.g., Balancing Authority(ies), specific generators, markets …) from which generation supporting each GCIR value of 3.1.1.1 and 3.1.1.2 will be supplied or the specific ATC Paths to be used for import of the generation supporting the GCIR.

**R3.1.2.** Identification of all applicable reserve margin and resource adequacy requirements, and the entity(ies) responsible for establishing them, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities.

3.1.2.1. The process and periodicity of calculating or recalculating GCIR if the entities specified in R3.1.2 require calculating GCIR on a frequency different than specified in R3.1.1

**R3.1.3.** A summary of the results of resource studies performed to determine the amount of the request, not to include confidential information.

**R3.1.4.** All resource studies (and supporting information) performed to determine the amount of the request.

**R3.2.** Every thirty-one calendar days, each Load Serving Entity or Planned Resource Sharing Group shall adjust its GCIR request, if necessary per 3.1.1 or 3.1.2.1, to reflect any incremental increase or decrease in required GCIR by either simple adjustment or through recalculation. .

**R3.3.** Base the request provided per R3.1 on studies conducted in accordance with verifiable historical, state, regional transmission organization or regional entity criteria.

**R4.** Within fourteen calendar days of receiving a request or change to a GCIR request that meets the requirements defined in R3.1, the Transmission Service Provider shall set the CBM for the next 13 months requested as described in R3.1 as follows: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Determine the amount of CBM (for use in R4.2) for each request by using one of the following:

**R4.1.1.** For the Area Interchange Methodology and the Rated System Path Methodology, using the requested Generation Capability Import Requirement for the appropriate ATC Path(s)

**R4.1.2.** For the Flowgate Methodology, determining the significant impacts of each request on each Flowgate

4.1.2.1. Determine impacts of a request by multiplying the requested GCIR by the Distribution Factor for the import relative to the Flowgate or model the GCIR explicitly in the AFC model per R3.1.1.3 and R3.1.1.4.

**R4.2.** For the Area Interchange Methodology and the Rated System Path Methodology, set CBM for each ATC Path equal to the sum of all requests such that all requests can be met simultaneously or all firm ATC has been allocated to CBM as follows:

**R4.2.1.** If the situation exists where there is insufficient capability on the ATC Path to satisfy the sum of all GCIR requests and the Transmission Service Provider, per R1.4, does not allow ATC to be less than zero, then the Transmission Service Provider shall set the CBM such that the monthly ATCs equal zero

**R4.2.2.** If the situation exists where there is insufficient capability on the ATC Path to satisfy the sum of all GCIR requests and the Transmission Service Provider, per R1.4, allows the ATC to be less than zero, then the Transmission Service Provider shall set the CBM equal to the sum of the requested GCIR for that ATC Path.

**R4.3.** For the Flowgate Methodology set CBM for each Flowgate equal to the sum of all requests on that Flowgate such that all requests can be met simultaneously or all firm ATC has been allocated to CBM as follows:

**R4.3.1.** If the situation exists where there is insufficient Flowgate AFC to satisfy the sum of all GCIR requests and the Transmission Service Provider, per R1.4, does not allow the Flowgate AFC to be less than zero, then the Transmission Service Provider shall set the CBM such that the monthly Flowgate AFCs equal zero

**R4.3.2.** If the situation exists where there is insufficient Flowgate AFC to satisfy the sum of all GCIR requests and the Transmission Service

Provider, per R1.4, allows the Flowgate AFC to be less than zero, then the Transmission Service Provider shall set the CBM equal to the sum of the requested GCIR for that Flowgate.

**R5.** Within sixty calendar days of receiving a request or change to a GCIR request that meets the requirements defined in R3.1, the Transmission Planner shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** As per R3.1.1.3 and R3.1.1.4, model the GCIR explicitly in the ATC/AFC model or use the CBM calculated using requirements R4.1 through R4.3 for all years requested beyond 13 months not to exceed 10 years

**R5.2.** If so requested, provide the Transmission Service Provider with the following:

**R5.2.1.** The total amount of CBM for each ATC Path or Flowgate on the Transmission Service Provider's system in each of the years specified in the original CBM request not to exceed 10 years.

**R5.2.2.** If less than the sum of all requests was established as the CBM for any period, for each ATC Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the years specified in the original request not to exceed 10 years.

**R6.** Within seven calendar days of the determination of CBM as described in R4 or R5, the Transmission Service Provider shall provide each Load-Serving Entity or Planned Resource Sharing Group that requested CBM and the Balancing Authority hosting its (their) load with a report that includes: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** The total amount of CBM for each ATC Path or Flowgate on the Transmission Service Provider's system in each of the months or years specified in the original request.

**R6.2.** If less than the sum of all requests was established as the CBM for any period:

- For each ATC Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the months and years specified in the original request
- The option to pursue alternatives, including expansion, with the Transmission Service Provider.

**R7.** The Transmission Service Provider and Transmission Planner shall each provide copies of the supporting data, including any models, used for allocating CBM over each ATC Path or Flowgate to the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

**R7.1.** Each of its associated Transmission Operators within thirty calendar days of their making a request for the data.

**R7.2.** To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, or Planning Coordinator within thirty calendar days of their making a request for the data.

**R8.** The Load-Serving Entity or Balancing Authority that wants to schedule energy over firm Transfer Capability set aside as CBM shall submit an Arranged Interchange, and shall not request to schedule energy over firm Transfer Capability set aside as CBM unless experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. *[Violation Risk Factor: Lower] [Time Horizon: Same-day Operations]*

**R9.** When reviewing an Arranged Interchange using CBM, the Balancing Authority and Transmission Service Provider shall waive, within the bounds of reliable operation, any real-time timing and ramping requirements. *[Violation Risk Factor: Lower] [Time Horizon: Same-day Operations]*

**R10.** The Transmission Service Provider shall approve any Arranged Interchange using CBM that is submitted by an Energy Deficient Entity[1] under an EEA2 if the CBM is available. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

## C. Measures

**M1.** Each Transmission Service Provider shall produce its CBMID evidencing inclusion of all information specified in R1. (R1)

**M2.** Each Transmission Service Provider shall have evidence (such as dated logs and data, copies of dated electronic messages, or other equivalent evidence) to show that prior to the effective date of a change to its CBMID, it made the CBMID available to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators specified in R2. (R2)

**M3.** Each Load-Serving Entity or Planned Resource Sharing Group that wants CBM shall provide a copy of its GCIR request with the supporting information specified in R3.1 to show that it is compliant with R3.1. (R3)

**M4.** Each Load-Serving Entity or Planned Resource Sharing Group that requests changes to its GCIR as per R3.2 shall provide dated copies of its updated GCIR along with studies or documentation of the changes that support its request; such as Transmission Service Requests, generator outage reports, and load-forecast changes that affect its resource adequacy requirements documented in R3.1.2. (R3).

**M5.** Each Load-Serving Entity or Planned Resource Sharing Group that wants CBM shall provide evidence (such as studies, historical data, copies of state or regional transmission organization reliability criteria, regional generation reliability criteria or other equivalent evidence) that it has based its GCIR request on verifiable historical, state, regional transmission organization, or regional generation reliability criteria in accordance with R3.3. (R3)

**M6.** Each Transmission Service Provider shall provide evidence including copies of GCIR requests and requests for GCIR changes and other evidence such as copies of the actual computations to set CBM, or other equivalent evidence to show that CBM for the months requested as described in R3.1.1 has been established using the process described in R4. (R4)

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[1] See Attachment 1-EOP-002-0 for definition.

**M7.** Each Transmission Planner shall provide evidence including copies of GCIR requests and requests for GCIR changes and other evidence (such as written documentation of studies and supporting study models that model base load flow, copies of actual computations to set CBM, or other equivalent evidence) to show that the GCIR has been used to either model GCIR or calculate as per the process described in R5. (R5)

**M8.** Each Transmission Service Provider shall provide copies of the reports sent to Load-Serving Entities and Balancing Authorities along with other evidence (such as logs and data, copies of electronic messages, or other equivalent evidence) to show that within seven calendar days of the determination of CBM, a report meeting the requirements described in R6 was provided as specified. (R6).

**M9.** Each Transmission Service Provider and Transmission Planner shall each provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in R7. (R7)

**M10.** Each Load-Serving Entity that scheduled energy over firm Transfer Capability set aside as CBM shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time they requested the schedule using CBM, they were in an EEA2. (R8)

**M11.** Each Balancing Authority and Transmission Service Provider shall provide evidence (such as operating logs and tag data) that it waived real-time timing and ramping requirements when approving an Arranged Interchange using CBM (R9)

**M12.** Each Transmission Service Provider shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any Arranged Interchange using CBM for any Energy Deficient Entity[2] where the total CBM available was greater than the amount of CBM requested in the Arranged Interchange. (R10)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority (CEA)

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall maintain its current, in force CBMID and any prior versions of the CBMID that were in force since the last compliance audit to show compliance with R1.

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[2] See Attachment 1-EOP-002-0 for definition.

- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7 and R10 for the most recent three calendar years plus the current year.
- The Load-Serving Entity and Planned Resource Sharing Group shall each maintain evidence to show compliance with R3, and R8 for the most recent three calendar years plus the current year.
- The Transmission Planner shall maintain evidence to show compliance with R5 and R7 for three calendar years.
- The Balancing Authority shall maintain evidence to show compliance with R9 for three calendar years.
- If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

**None.**

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made within the last three months. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago.<br>**OR**<br>The Transmission Service Provider's CBMID does not address one of the sub requirements. | The Transmission Service Provider has CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago.<br>**OR**<br>The Transmission Service Provider's CBMID does not address two of the sub requirements. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made more than twelve months ago.<br>**OR**<br>The Transmission Service Provider does not have a CBMID;<br>**OR**<br>The Transmission Service Provider's CBMID does not address three or more of the sub requirements. |
| R2. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator 14 or more calendar days but not more than 30 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator 30 or more calendar days but not more than 60 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator 60 or more calendar days but not more than 90 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator more than 90 calendar days after a change was made. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit the information required by any one of the following: R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 20MW or 10%, whichever is smaller, and not more than 30MW or 20%, whichever is smaller. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit the information two or more of the following: R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 30MW or 20%, whichever is smaller, and not more than 40MW or 30%, whichever is smaller. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not include one or more of the items specified in R3.1.1 in its request.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit any of the information described in R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 40MW or 30%, whichever is smaller.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group requested GCIR greater than its needs for imports to meet reserve margin or resource adequacy requirements (not to include the incremental power flows from reserve sharing requirements), and the additional GCIR |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | requested was more than 10MW in excess of the needed amount. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | N/A | N/A | The Transmission Service Provider set CBM for the months requested as described in R4 more than 14, but not more than 30 calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Service Provider did not follow the process described in R4. | The Transmission Service Provider set CBM for the months requested as described in R4 more than 30 calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Service Provider did not follow the process described in R4 and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met. |
| R5. | N/A | N/A | The Transmission Planner set CBM for the years requested as described in R5 more than 60, but not more than 120, calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Planner did not follow the process described in R5. | The Transmission Planner set CBM for the years requested as described in R5 more than 120 calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Planner did not follow the process described in R5, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met. |
| R6. | The Transmission Service Provider provided the report to the requesting entities in more than 7 calendars days but not more than 9 calendar days of determining the CBM | The Transmission Service Provider provided the report to the requesting entities in 9 or more calendar days but not more than 14 calendar days of determining CBM | The Transmission Service Provider provided the report to the requesting entities in 14 or more calendar days but not more than 22 calendar days of determining CBM | The Transmission Service Provider provided the report to the requesting entities 22 or more calendar days after determining CBM or did not provide the report. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R7. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM in more than seven, but not more than fourteen, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM in more than fourteen, but not more than thirty, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM more than thirty, but not more than sixty, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM more than sixty days after the submission of the request. |
| R8. | N/A | N/A | N/A | A Load Serving Entity requested to schedule energy over CBM while not in an EEA2 |
| R9. | N/A | N/A | N/A | A Balancing Authority or Transmission Service Provider denied an Arranged Interchange using CBM based on timing or ramping requirements. |
| R10. | N/A | N/A | N/A | The Transmission Service Provider failed to approve an Arranged interchange for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available.” |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 14, 2007.

**Description of Current Draft:**

This is the third and final draft of the proposed standard posted for stakeholder comments. This draft includes the modifications with consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Generation Capability Import Requirement (GCIR):** The amount of generation capability from external sources requested by a Load-Serving Entity (LSE) (or group of LSEs with an aggregated need for Capacity Benefit Margin) to meet its generation reliability or resource~~serve~~ adequacy requirements as an alternative to internal resources.

**Capacity Benefit Margin Implementation Document (CBMID):** A document that describes the implementation of a Capacity Benefit Margin methodology.

**Planned Resource Sharing Group (PRSG):** A group of Load-Serving Entities who have agreed to jointly meet their resource adequacy requirements~~.~~.

## A. Introduction

1. **Title:** **Capacity Benefit Margin**

2. **Number:** **MOD-004-1**

3. **Purpose:** To promote the consistent and ~~transparent~~ reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support ~~reliable~~ analysis and system operations.

4. **Applicability:**

   **4.1. Functional Entity:**

   **4.1.1** Load-Serving Entity.

   **4.1.2** Planned Resource Sharing Group.

   **~~4.1.2~~4.1.3** Transmission Service Providers that maintain CBM.

   **~~4.1.3~~4.1.4** Balancing Authority.

   **~~4.1.4~~4.1.5** Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM.

5. **Facility Limitations/Specifications:**

   **5.1.** None.

6. **Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that ~~all six~~ this standard~~s~~ ~~are~~ is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard ~~Reliability Standards~~ become effective on the first day of the first calendar quarter that is twelve months beyond the date ~~the set of~~this standard~~s~~ ~~are~~ is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service Provider shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

**R1.1.** Its procedure for a Load-Serving Entity or Planned Resource Sharing Group within a Balancing Authority associated with the Transmission Service Provider to request ~~CBM to support its~~ the Generation Capability Import Requirement (GCIR) including the disposition and handling of deficient requests~~; and~~.

**R1.2.** Its procedure and assumptions for setting CBM for each ~~Posted~~ ATC Path or Flowgate based on Load-Serving Entity or ~~PRSG~~Planned Resource Sharing Group GCIR~~requests~~.

**R1.3.** Its procedure ~~for a Load-Serving Entity~~ to request the ~~scheduling of energy over~~ u~~tilizatio~~se~~n~~ of Transfer Capability set aside as CBM.

**R1.4.** A statement of whether the Transmission Service Provider allows ATC or AFC to be less than zero due to CBM.

**R2.** The Transmission Service Provider shall make available ~~the~~ its CBMID and any changes to the CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area prior to the effective date ~~within seven days~~ of a change. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.** A Load-Serving Entity ~~(~~or ~~PRSG~~Planned Resource Sharing Group~~group of Load-Serving Entities with an aggregated need for CBM)~~ that wants Transfer Capability to be set aside in the form of CBM shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

**R3.1.** Submit an annual ~~request for CBM~~ GCIR request to the Transmission Service Provider and Transmission Planner per the specifications in the CBMID ~~identifying the amount of CBM requested for each month for each year for the next ten year period,~~ that includes:

**R3.1.1.** The GCIR, specifying:

~~3.1.1.1.The Balancing Authority(ies) from which generation supporting the GCIR will be supplied or the specific Posted Paths to be utilized for import of the generation supporting the GCIR.~~

~~3.1.1.2.~~3.1.1.1. A monthly GCIR value for each month for the next 24 months. If monthly values are not a requirement as per the applicable reserve margin and resource adequacy requirements documented in R3.1.2, a yearly GCIR value ~~will be sufficient~~ for the current ~~during the current year~~ and following year will be sufficient ~~for each Balancing Authority or Posted Path~~.

3.1.1.2. An annual GCIR value for each subsequent year for each Balancing Authority or Posted Path not to exceed 10 years into the future.

3.1.1.3. The location of the load ~~being~~ served by the GCIR (e.g., Balancing Authority, zones, markets ~~, etc~~…).

3.1.1.4. Assumed external resources (e.g., Balancing Authority(ies), specific generators, markets ~~, etc~~…) from which generation supporting each GCIR value of 3.1.1.1 and 3.1.1.2 will be supplied or the specific ATC Paths to be u~~tiliz~~sed for import of the generation supporting the GCIR.

**R3.1.2.** Identification of all applicable reserve margin and resource adequacy requirements, and the entity(ies) responsible for establishing them, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities.

3.1.2.1. The process and periodicity of calculating or recalculating GCIR if the entities specified in R3.1.2 require calculating GCIR on a frequency different than specified in R3.1.1

**R3.1.3.** A summary of the results of resource studies performed to determine the amount of the request, not to include confidential information.

**R3.1.4.** All resource studies (and supporting information) performed to determine the amount of the request.

**R3.2.** ~~At least e~~Every thirty-one calendar days, each Load Serving Entity or ~~PRSG~~Planned Resource Sharing Group shall ~~review its GCIR request and~~ adjust~~ that~~ its GCIR request, if necessary per 3.1.1 or 3.1.2.1, to reflect any incremental increase or decrease in required GCIR by either simple adjustment or through recalculation. ~~update the request provided per R3.1 to reflect any changes that alter future needs for CBM or indicate that no change is needed~~.

**R3.3.** Base the request provided per R3.1 on studies conducted in accordance with verifiable historical, state, regional transmission organization or regional entity criteria.

**R4.** Within fourteen calendar days of receiving a request or change to a ~~request for CBM~~ GCIR request that meets the requirements defined in R3.1, the Transmission Service Provider shall set the CBM for the next 13 months requested as described in R3.1~~.1.2~~ as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.1.** Determine the amount of CBM (for use in R4.2) for each request by using one of the following~~:~~:

**R4.1.1.** For the Area Interchange Methodology and the Rated System Path Methodology, using the requested Generation Capability Import Requirement for the appropriate ATC~~Posted~~ Path(s)

**R4.1.2.** For the Flowgate Methodology, determining the significant impacts of each request on each Flowgate

4.1.2.1. Determine impacts of a request by multiplying the requested GCIR by the Distribution Factor for the ~~transfer of that~~ import ~~from the specified Balancing Authority~~ relative to the Flowgate or model the GCIR explicitly in the AFC model per R3.1.1.3 and R3.1.1.4.

~~4.1.2.2.Classify each impacts based on a Distribution Factor of 3% or greater as a significant impact.~~

**R4.2.** For the Area Interchange Methodology and the Rated System Path Methodology, ~~S~~set CBM for each ~~Posted~~ ATC Path ~~or Flowgate based on~~ equal to the sum of all requests such that all requests can be met simultaneously or all firm ATC ~~or AFC~~ has been allocated to CBM as follows:

~~**R4.2.1.**For Posted Paths, set the CBM for each Posted Path equal to the lesser of:~~

**R4.2.1.** If the situation exists where there is insufficient capability on the ATC Path to satisfy ~~T~~the sum of all ~~requests for GCIR~~GCIR requests and the Transmission Service Provider, per R1.4, does not allow ATC to be less than zero, then the Transmission Service Provider ~~w~~shaiill set the CBM such that the monthly ATCs equal~~s~~ zero

**R4.2.2.** If the situation exists where there is insufficient capability on the ATC Path to satisfy the sum of all ~~requests for GCIR~~GCIR requests and the Transmission Service Provider, per R1.4, allows the ATC to be less than zero, then the Transmission Service Provider- ~~wi~~shall set the CBM equal to the sum of the requested GCIR for that ATC Path. ~~for that Posted Path, minus the transfer capability set aside for reserve sharing for that Posted Path or~~

~~-The firm Available Transfer Capability (ATC) for that Posted Path~~

**R4.3.** For the Flowgate Methodology~~s,~~ set ~~the~~ CBM for each Flowgate equal to the sum of all requests on that Flowgate such that all requests can be met simultaneously o~~f~~r all firm ATC has been allocated to CBM as follows~~:lesser of~~:

**R4.3.1.** If the situation exists where there is insufficient Flowgate AFC to satisfy the sum of all ~~requests for GCIR~~GCIR requests and the Transmission Service Provider, per R1.4, does not allow the Flowgate AFC to be less than zero, then the Transmission Service Provider ~~wi~~shall set the CBM such that the monthly Flowgate AFCs equal~~s~~ zero

**R4.3.2.** If the situation exists where there is insufficient Flowgate AFC to satisfy the sum of all ~~requests for GCIR~~GCIR requests and the Transmission Service Provider, per R1.4, allows the Flowgate AFC to be less than zero, then the Transmission Service Provider shall set the CBM equal to the sum of the requested GCIR for that Flowgate.

~~-The sum of the significant impacts of all requests for GCIR for that Flowgate minus the impact of transfer capability set aside for reserve sharing for that Flowgate, or~~

~~-The firm Available Flowgate Capability (AFC) for that Flowgate~~

~~**R4.4.**If the sum of all CBM requests can not be met simultaneously, and during the evaluation of monthly ATC or AFC, additional capacity becomes available, increase the CBM based on availability up to a maximum of the sum of all CBM requests.~~

**R5.** Within sixty calendar days of receiving a request or change to a ~~request for CBM~~ GCIR request that meets the requirements defined in R3.1, the Transmission Planner shall: ~~set the CBM for the years requested as described in R3.1.1.3 as follows:~~ [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** As per R3.1.1.3 and R3.1.1.4, model the GCIR explicitly in the ATC/AFC model or use the CBM calculated using requirements R4.1 through R4.3 for all years requested beyond 13 months not to exceed 10 years

~~**R5.1.**Use each GCIR to determine a margin to decrement Firm Transfer Capability for use in all future planning processes.~~

~~**R5.2.**Set the CBM for each Posted Path or Flowgate based on the sum of all CBM requests such that all requests can be met simultaneously or all available firm Transfer Capability has been allocated to CBM.~~

~~**R5.3.**If the sum of all requests can not be met simultaneously, and during the planning process, additional capacity becomes available, increase the CBM based on availability up to a maximum of the sum of all requests.~~

~~**R5.4.**~~**R5.2.** If so requested, ~~P~~provide the Transmission Service Provider with the following:

~~**R5.4.1.**~~**R5.2.1.** The total amount of CBM for each ~~Posted~~ ATC Path or Flowgate on the Transmission Service Provider's system in each of the years specified in the original CBM request not to exceed 10 years.

~~**R5.4.2.**~~**R5.2.2.** If less than the sum of all requests was established as the CBM for any period, for each ~~Posted~~ ATC Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the years specified in the original request not to exceed 10 years.

**R6.** Within ~~five~~ seven calendar days of the determination of CBM as described in R4 or R5, the Transmission Service Provider shall provide each Load-Serving Entity ~~(or group of Load-Serving Entities with an aggregated need for CBM)~~ or ~~PRSG~~Planned Resource Sharing Group that requested CBM and the Balancing Authority hosting its (their) load with a report that includes: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** The total amount of CBM for each ~~Posted~~ ATC- Path or Flowgate on the Transmission Service Provider's system in each of the months or years specified in the original request.

**R6.2.** If less than the sum of all requests was established as the CBM for any period:

- For each ~~Posted~~ ATC Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the months and years specified in the original request
- The option to pursue alternatives, including expansion, with the Transmission Service Provider~~request a system impact study~~.

**R7.** The Transmission Service Provider and Transmission Planner shall each provide copies of the supporting data, including any models, used for allocating CBM over each ~~Posted~~ ATC Path or Flowgate to the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

**R7.1.** Each of its associated Transmission Operators within ~~seven~~ thirty calendar days of their making a request for the data~~a modification to the CBM~~.

**R7.2.** To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, or Planning Coordinator within ~~seven~~ thirty calendar days of their making a request for the data.

**R8.** The Load-Serving Entity or Balancing Authority that wants to schedule energy over ~~Firm~~ firm Transfer Capability set aside as CBM shall submit an Arranged Interchange

~~Transaction Tagto the Interchange Authority~~, and shall not request to schedule energy over ~~F~~firm Transfer Capability set aside as CBM unless experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [*Violation Risk Factor: Lower*] [*Time Horizon: Same-day Operations ~~Planning~~*]

**R9.** When reviewing an Arranged Interchange ~~Transaction Tag~~ using CBM, the Balancing Authority and Transmission Service Provider shall waive, within the bounds of reliable operation, any real-time timing and ramping requirements. [*Violation Risk Factor: Lower*] [*Time Horizon: Same-day Operations ~~Planning~~*]

**R10.** The Transmission Service Provider shall approve any Arranged Interchange ~~Transaction Tag~~ using CBM that is submitted by an Energy Deficient Entity[1] under an EEA2 if the CBM is available. [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations ~~Planning~~*]

[1] See Attachment 1-EOP-002-0 for definition.

## C. Measures

**M1.** Each Transmission Service Provider shall produce ~~have~~ its CBMID evidencing inclusion of all ~~specified that includes the~~ information specified in ~~specified in~~ R1~~ as to show that it is compliant with R1~~. (R1)

**M2.** ~~The~~ Each Transmission Service Provider shall have evidence (such as dated logs and data, copies of dated electronic messages, or other equivalent evidence) to show that prior to the effective date ~~within seven days~~ of a change to its CBMID, it made the CBMID available to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators specified in R2. (R2)

**M3.** ~~The~~ Each Load-Serving Entity or ~~PRSG~~Planned Resource Sharing Group that wants CBM shall provide a copy of its ~~CBM~~ GCIR request with the supporting information specified in R3.1 to show that it is compliant with R3.1. (R3)

**M4.** ~~The~~ Each Load-Serving Entity or ~~PRSG~~Planned Resource Sharing Group that requests changes to its GCIR~~wants CBM~~ as per R3.2 shall provide dated copies of its updated ~~CBM~~ GCIR along with studies or documentation of the changes ~~which~~that support ~~their~~its request; such as Transmission Service Requests, generator outage reports, and load-forecast changes ~~which~~that affect ~~their~~ its resource adequacy requirements documented in R3.1.2. ~~requests as evidence that it has updated its CBM request or confirmed no update was needed at least every thirty-one days, per R3.2~~ (R3).

**M5.** ~~The~~ Each Load-Serving Entity or ~~, PRSG~~Planned Resource Sharing Group that wants CBM shall provide evidence (such as studies, historical data, copies of state or regional transmission organization reliability criteria, regional generation reliability criteria or other equivalent evidence) that ~~they~~ it has based its ~~CBM~~GCIR request on verifiable historical, state, regional transmission organization, or regional generation reliability criteria in accordance with R3.3. (R3)

**M6.** ~~The~~ Each Transmission Service Provider shall provide evidence including copies of ~~requests for CBM~~ GCIR requests and requests for GCIR changes ~~to CBM GCIR~~ and other evidence such as copies of the actual computations to set CBM, or other equivalent evidence to show that CBM for the months requested as described in R3.1.1~~.2~~ has been established using the process described in R4. (R4)

**M7.** ~~The~~ Each Transmission Planner shall provide ~~evidence~~ evidence ~~(such as written documentation of studies and supporting study models that model base loadflow)~~ including copies of ~~requests for CBM~~ GCIR requests and requests for GCIR changes ~~to CBM GCIR~~ and other evidence (such as written documentation of studies and supporting study models that model base load flow, ~~such as~~ copies of actual computations to set CBM, or other equivalent evidence)~~-~~ to show that the GCIR has been used to either model GCIR or calculate as per the process ~~CBM for the years requested as described in R3.1.1.3 has been established using the process~~ described in R5. (R5)

~~**M8.** The Transmission Planner shall provide evidence (such as written documentation of studies and supporting study models that model, in base loadflows, the GCIRs as~~

~~identified in R3.1.1 by Load-Serving Entities) that demonstrates that the CBM has been used to determine a margin to decrement Firm Transfer Capability in planning processes as specified in R5.1. (R5)~~

**~~M9.~~M8.** ~~The~~Each Transmission Service Provider shall provide copies of the reports sent to Load-Serving Entities and Balancing Authorities along with other evidence (such as logs and data, copies of electronic messages, or other equivalent evidence) to show that within ~~five~~ seven calendar days of the determination of CBM, a report meeting the requirements described in R6 was provided as specified. (R6).

**~~M10.~~M9.** ~~The~~ Each Transmission Service Provider and Transmission Planner shall each provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show- that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in R7. (R7)

**~~M11.~~M10.** ~~The~~ Each Load-Serving Entity that scheduled energy over firm Transfer Capability set aside as CBM shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time they requested ~~a~~ the schedule using CBM, they were in an EEA2. (R8)

**~~M12.~~M11.** Each Balancing ~~Authorities~~ Authority and Transmission Service Provider~~s~~ shall provide evidence (such as operating logs and tag data) that it waived real-time timing and ramping requirements when approving an ~~they did not deny an Interchange Schedule~~Arranged Interchange using CBM ~~based on the request not meeting timing or ramping requirements.~~ (R9)

**~~M13.~~M12.** ~~The~~ Each Transmission Service Provider shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any ~~Interchange Transaction Tag~~Arranged Interchange using CBM for any ~~energy~~ Energy ~~deficient~~ Deficient ~~entity~~ Entity[2] where the total CBM available was greater than the amount of CBM requested in the ~~Tag~~Arranged Interchange. (R10)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority (CEA)

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

[2] See Attachment 1-EOP-002-0 for definition.

- The Transmission Service Provider shall maintain its current, in force ~~ATCID~~ CBMID and any prior versions of the ~~ATCID~~ CBMID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7 and R10 for the most recent three calendar years plus the current year.
- The Load-Serving Entity ~~or~~and ~~PRSG~~Planned Resource Sharing Group shall each maintain evidence to show compliance with R3, and R8 for the most recent three calendar years plus the current year.
- The Transmission Planner shall maintain evidence to show compliance with R5 and R7 for three calendar years.
- The Balancing Authority shall maintain evidence to show compliance with R9 for three calendar years.
- If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

**None.**

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made within the last three months. | The Transmission Service Provider has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago.<br>**OR**<br>The Transmission Service Provider's CBMID does not address one of the sub requirements. | The Transmission Service Provider has CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago.<br>**OR**<br>The Transmission Service Provider's CBMID does not address two of the sub requirements. | The Transmission Service Provider ~~does not have a CBMID, or~~ has a CBMID that does not incorporate changes that have been made more than twelve months ago.<br>**OR**<br>The Transmission Service Provider does not have a CBMID;<br>**OR**<br>The Transmission Service Provider's CBMID does not address three or more of the sub requirements. |
| R2. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator ~~eight (8)~~14 or more calendar days but not more than ~~14~~ 30 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator ~~14~~ 30 or more calendar days but not more than ~~21~~ 60 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator ~~21~~ 60 or more calendar days but not more than ~~28~~ 90 calendar days after a change was made. | The Transmission Service Provider makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator more than ~~28~~ 90 calendar days after a change was made. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Load Serving Entity or Planned Reserve Sharing Group did not update ~~their~~ its request for CBM, or indicate that no update was needed, as described in R3.2. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit the information ~~described in~~ required by any one of the following: R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update ~~their~~ its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 20MW or 10%, whichever is smaller, and not more than 30MW or 20%, whichever is smaller. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit the information ~~described in any one~~two or more of the following: R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update ~~their~~ its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 3~~2~~0MW or 2~~1~~0%, whichever is smaller, and not more than 40MW or 30%, whichever is smaller. | The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not include one or more of the items specified in R3.1.1 in ~~their~~ its request.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit any of the information described in R3.1.2, R3.1.3, or R3.1.4.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group did not update ~~their~~ its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 40MW or 30%, whichever is smaller.<br>**OR**<br>The Load Serving Entity or Planned Reserve Sharing Group requested GCIR greater than its needs for imports to meet reserve margin or resource adequacy requirements (not to include the incremental power flows from reserve sharing requirements), and the additional GCIR |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | requested was more than 10MW in excess of the needed amount. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | N/A | N/A | The Transmission Service Provider set CBM for the months requested as described in R~~3.1.1.2~~ 4 more than 14, but not more than 30~~,~~ calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Service Provider did not follow the process described in R4~~.1, R4.2, and R4.3~~. | The Transmission Service Provider set CBM for the months requested as described in R~~3.1.1.2~~ 4 more than 30 calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Service Provider did not follow the process described in R4~~.1, R4.2, and R4.3,~~ and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met. |
| R5. | N/A | N/A | The Transmission Planner set CBM for the years requested as described in R~~3.1.1.3~~ 5 more than 60, but not more than 120, calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Planner did not follow the process described in R5~~.1, R5.2, R5.3, and R5.4~~. | The Transmission Planner set CBM for the years requested as described in R~~3.1.1.3~~ 5 more than 120 calendar days after receiving a request for CBM.<br>**OR**<br>The Transmission Planner did not follow the process described in R5~~.1, R5.2, R5.3, and R5.4~~, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met. |
| R6. | The Transmission Service Provider provided the report to the requesting entities in more than ~~5~~7 calendars days but not more than ~~within 7~~9 calendar days ~~(up to 2 days late)~~ of | The Transmission Service Provider provided the report to the requesting entities in ~~7~~9 or more calendar days but not more than ~~within~~ 1~~2~~4 calendar days ~~(up to 7 days late)~~ of | The Transmission Service Provider provided the report to the requesting entities in 1~~2~~4 or more calendar days but not more than 2~~0~~2 calendar days ~~within 19 days (up to 14 days~~ | The Transmission Service Provider provided the report to the requesting entities ~~within 20~~ 22 or more calendar days ~~of~~ after determining CBM or did not provide the report. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | determining the CBM | determining CBM | ~~late)~~ of determining CBM | |
| R7. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM in more than seven, but not more than fourteen, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM in more than fourteen, but not more than thirty, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM more than thirty, but not more than sixty, days after the submission of the request. | The Transmission Service Provider or Transmission Planner did not provide a requester specified in R5 with the supporting data, including models, used to allocate CBM more than sixty days after the submission of the request. |
| R8. | N/A | N/A | N/A | A Load Serving Entity requested to schedule energy over CBM while not in an EEA2 |
| R9. | N/A | N/A | N/A | A Balancing Authority or Transmission Service Provider denied an ~~Interchange Transaction Tag~~Arranged Interchange using CBM based on timing or ramping requirements. |
| R10. | N/A | N/A | N/A | The Transmission Service Provider failed to approve an Arranged interchange for CBM submitted by an Energy Deficient Entity under an EEA2 when CBM was available."~~The responsible entity has failed to demonstrate implementation or execution of the program/procedure requirement~~ |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | ~~or directive~~ |

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# Implementation Plan for Standard MOD-004-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-004-1, which describes the reliability aspects of determining and maintaining a Capacity Benefit Margin and the conditions under which that margin may be used.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes MOD-004-0. MOD-005-0, MOD-006-0, and MOD-007-0 have been incorporated into this standard, made irrelevant by this standard, or are being addressed by the North American Energy Standards Board, and should be retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-004-1 | | ■ | ■ | ■ | | ■ |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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## Summary Consideration of Comments:

The Drafting Team has reviewed the comments and made some changes to the standard to address these comments.

1. Based on industry comments, as well as those of the Functional Model Working Group, the Planned Resource Sharing Group (PRSG) has been eliminated.  To address regional CBM processes, the Resource Planner was added as an applicable entity.  Entities still may elect to register as a Joint Registration Organization (JRO), as well as delegate tasks.

2. The drafting team has modified the standard to be less prescriptive and allow for more flexibility in how the need for CBM and CBM itself is determined.

3. The requirement to waive timing and ramping requirements was modified to have a VRF of medium, as it has a direct impact on current-day operations and can result in the inadvertent denial of an interchange transaction needed to maintain reliability.

4. The requirement for a Transmission Service Provider to approve transactions using CBM if the CBM is available was modified to apply additional criteria to the evaluation for approval.

5. A more graded approach was applied to the VSLs where appropriate.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.

| Entity | Comment |
|---|---|
| Bonneville Power Administration | The purpose statement for MOD-004 should be expanded, to describe the timeframe for which CBM is to be activated so as not to conflict with TRM, to include a statement that "CBM is to be scheduled by the Energy Deficient Entity experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher only in the hour following a generation forced outage event." |
| Response: The drafting team disagrees with this interpretation. TRM may be used within the current hour for reserve sharing, but is a margin used to respond to events. CBM may be used at any point, and for a period longer than the current hour, subject to existing scheduling rules and requirements. | |
| CenterPoint Energy | ERCOT's filed comments to the SDT that ATC, TTC, CBM, and TRM are not applicable within ERCOT operations and that these Standards should have provisions that make it clear that these requirements apply only within market structures in which they are pertinent were ignored by the SDT. These standards should not apply to ERCOT, thus our negative vote. |
| Response: The drafting team believes that the standards as written do largely exempt ERCOT if ERCOT does not use CBM. However, ERCOT is still required, if providing service related to another entity's use of CBM, to waive timing and ramping requirements if such waiver can be provided reliably. | |
| Consolidated Edison Co. of New York | PSRG is not an entity defined in the NERC functional Model, too many changes to requirements from last draft - this is not following standards development process - standard should be out for comments again, not up for approval vote. |
| Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment. | |
| Exelon Energy | R1.5. A statement should be added to confirm that it shall use assumptions in calculating CBM that are consistent with those assumptions that are used in the Transmission planning process " |
| Response: The drafting team believes that CBM can be based on studies and requirements outside the scope of the Transmission planning process defined in the TPL standards. | |
| FirstEnergy Energy Delivery | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br>CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc. FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both.<br>Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td></td><td>Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br><br>Response: The standards are being posted for comment.<br><br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br><br>– The Planning Coordinator (PC) should replace the Transmission Planner (TP) as the applicable entity. The requirements in R5 and R7 should be the ultimate responsibility of the PC who works with his associated TP to obtain the necessary information. Per the NERC functional model, the PC "coordinates and collects data for system modeling from the Transmission Planner and "coordinates total transfer capability with Transmission Planners.<br><br>Response: The drafting team agrees with the descriptions given from the functional model. However, we believe that the coordination functions of the Planning Coordinator do not apply here. CBM is the import capability of the local system to serve local needs. The Planning Coordinator’s role is to look at broader needs, and CBM by definition is a local need. Transmission Planners may, of course, delegate this task to the Planning Coordinator.<br><br>– This standard is too prescriptive with the detail into how CBM should be calculated across all interconnections and does not take into account all the different calculation methods currently used by various entities in the industry. It is suggested that the standard be more general and that some of the information contained is better suited with a guideline document for calculating CBM.<br><br>Response: The drafting team has modified the standard to be less prescriptive and allow for more flexibility in how the need for CBM and CBM itself is determined.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Great River Energy</td><td>GRE agrees with the PJM and MISO recommendation that the standard needs an additional commenting period based on the significance of the comments submitted during the previous commenting periods.</td></tr>
<tr><td colspan="2">Response: The drafting team is posting the standard for comment.</td></tr>
<tr><td>Hydro One Networks, Inc.</td><td>Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighboring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that</td></tr>
</table>

| Entity | Comment |
|---|---|
| | these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained,<br>Response: The drafting team does not believe that it is necessary for all entities to implement this standard at the same time, because there are no interdependencies between entities implementing CBM.<br>In addition we offer the following comments to the specific Standard MOD-004-1:<br>(a) Requirement 1.1 introduces the concept of an entity called the Planned Resource Sharing Group. This entity is not defined and is not currently in the approved version of the NERC Functional Model (v.3). Adding this entity raises issues for registration and compliance.<br>(b) Requirements have been introduced for the first time in this version. None of these revisions have yet been posted for comments by the industry. New requirements should not be introduced in the final version of a standard without affording the industry some opportunity to comment. This bypasses the intent of the ANSI approved NERC RS process.<br>Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment. |
| Response: Please see in-line responses. | |
| Hydro-Quebec TransEnergie | Requirement 1.1 adds the concept of Planned Resource Sharing Group. This entity is not defined and is not currently in NERC Functional Model (v.3). Adding entity is risky and raises the issue of registration. Should such a Planned Resource Sharing Group register even if it's not an entity defined in NERC Functional Model<br>– If not, what are the consequences<br>– It seems that the idea was to address the situation where an ISO, for example, would do it for other entities. We oppose the idea of introducing new entities in a standard. Moreover, many requirements are introduced for the first time in this version. None of these have thus been circulated for comment in the previous rounds. New requirements can't be introduced in the final version of a standard. It doesn't respect the voting process. |
| Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment. | |
| Kansas City Power & Light Co. | The CBM calculation should not be applicable to the LSE. Suggest removing LSE from applicability. |
| Response: Load Serving Entities have certain reliability obligations if they wish to use CBM. The standard describes those responsibilities, and the LSE is expected to meet those obligations. | |
| Municipal Electric Authority of Georgia | The Requirement R.8 implies that this standard would require TSPs to furnish CBM to "entities" that never requested or funded CBM. This unreasonable interpretation is expected to cause reliability problems for LSEs that currently rely on CBM.<br>From the proposed standard, some may even infer that all "entities" affiliated with the TSP's BA have an entitlement to use the TSP's CBM even if, for example, such "entities" have no transmission service contract with the TSP or such "entities" are insolvent. An obvious alternative interpretation, consistent with the terminology used in R.10, is that TSPs may reasonably conclude that CBM is not AVAILABLE to entities that have not made a valid CBM request (except to extent CBM capacity is |

| Entity | Comment |
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| | released and purchased non-firm).<br>Response: The drafting team has modified the standard to address this concern by only requiring a TSP to approve the transaction if the EEA 2 for which the CBM is being scheduled is within the Transmission Service Providers area. Issues related to creditworthiness are not within the scope of NERC.<br><br>Furthermore, the standard is silent on whether a TSP may prioritize competing requests to use CBM. Is the CBM first come, first served without any consideration of whether the requestor complied with the TSP's CBMID? If an LSE that reserved CBM loses a generator after all the CBM is in use by other "entities" that never requested CBM, does the TSP deny CBM to the LSE that requested and paid for it? Undoubtedly, if this standard is approved without changes, it would have to raise questions if the drafting team's interpretation comports with the Takings Clause of the Fifth Amendment to the U.S. Constitution.<br>Response: The drafting team believes that determinations such as those described are best left to business practices, as they are commercial in nature and deals primarily with equity between LSEs, rather than reliability. For this reason, the team took no position on the issue, and only required that use of CBM be approved if available – not denied if unavailable.<br><br>Finally, while some may argue that the drafting team's interpretation will improve reliability for customers of systems that are short on installed capacity (and this may be the case in the short-run), the unintended consequence is that entities that may already be irresponsibly under-resourced may further reduce their installed capacity investments once they learn they can free ride on their neighbors' CBM.<br>Response: The drafting team has modified the standard to address this concern by only requiring a TSP to approve the transaction if the EEA 2 for which the CBM is being scheduled is within the Transmission Service Providers area. |
| Response: Please see in-line responses. | |
| National Grid | This standard has added in the applicability section, an entity referred to as a Planned Resource Sharing Group. Requirement 1.1 adds this concept of an entity called the Planned Resource Sharing Group. This entity is not defined and is not currently in the latest approved version of the NERC Functional Model (v.3). Adding this entity raises issues for registration and compliance.<br>Additionally and more importantly, requirements have been introduced for the first time in this version of the standard. None of these revisions have yet been circulated for comment. New requirements should not be introduced in the final version of a standard without affording the industry some opportunity to comment. This, in our view bypasses the intent of the ANSI approved NERC RS process. |
| Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment. | |
| New Brunswick Power Transmission Corporation | There are new requirements introduced in this version that have not been circulated for comment. Requirement 1.1 adds and entity that has not been defined and is not in the current version of the NERC Functional model. |
| Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment. | |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td>New York Power Authority</td><td>Problems were found with the applicability section as it pertains to the planned resource sharing group. Requirement 1.1 adds this concept of an entity called the Planned Resource Sharing Group. This entity is not defined and is not currently in the latest approved version of the NERC Functional Model (v.3). Adding this entity raises issues for registration and compliance.<br><br>Additionally, requirements have been introduced for the first time in this version. None of these revisions have yet been circulated for comment. New requirements should not be introduced in the final version of a standard without affording the industry some opportunity to comment. This, in the view of the RSC bypasses the intent of the ANSI approved NERC RS process.</td></tr>
<tr><td colspan="2">Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment.</td></tr>
<tr><td>Northeast Utilities</td><td>The Applicability - Functional Entity section identifies the Planned Resource Sharing Group, which is not a functional entity identified in the latest version of the NERC Functional Model. Additionally, a number of requirements were added after the last posting which were not reposted for comments, and therefore bypassed the established standard development process.</td></tr>
<tr><td colspan="2">Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment.</td></tr>
<tr><td>Potomac Electric Power Co.</td><td>Potomac Electric agrees with the comments of PJM distributed to the ballot body. I will not repeat them here, but do include the headings:<br>I. The ATC MOD standards should have been sent out for comment not pre-ballot posting.<br>II. Depth of the ATC MOD standards is excessive.<br>III. Determining Violation Risk Factors is incorrect.<br>IV. Determining Violation Severity Levels is incomplete.</td></tr>
<tr><td colspan="2">Response: Please see response to PJM.</td></tr>
<tr><td>Public Service Electric and Gas Co.</td><td>PSE&G votes NO for the reasons expressed in PJM's comments.</td></tr>
<tr><td colspan="2">Response: Please see response to PJM.</td></tr>
<tr><td>Santee Cooper</td><td>The drafting team's response to Entergy regarding MOD-004-1 Requirement 8 implies that this standard would require a Transmission Service Provider to furnish CBM to any LSE or "entity" that never requested or funded CBM. Another unintended consequence of Requirement 8 is that entities (some that may already be irresponsibly under-resourced) may further reduce their installed capacity investments once they learn they can free ride on their neighbors' CBM.</td></tr>
<tr><td colspan="2">Response: Response: The drafting team has modified the standard to address this concern by only requiring a TSP to approve the transaction if the EEA 2 for which the CBM is being scheduled is within the Transmission Service Providers area.</td></tr>
<tr><td>Sierra Pacific Power Co.</td><td>I respectfully abstain from this ballot, as CBM is not currently a product that is utilized within our environment. Nonetheless, I would point out that there is no Reliability impact of any of the Requirements in the Standard.</td></tr>
<tr><td colspan="2">Response: CBM itself is a margin established for reliability purposes. To the extent entities utilize it to meet reliability objectives, it has reliability</td></tr>
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| Entity | Comment |
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| impact. Note that entities not using CBM are largely exempted from the standard. | |
| Southern Company Services, Inc. | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, it is recommended that only the LSE be applicable. There is not a PRSG function for which NERC can audit compliance. Additionally, the PRSG is a business arrangement and is not considered a reliability issue. |
| Response: The drafting team has removed the PRSG from the standard. However, the drafting team does believe entities other than the LSE are applicable. | |
| Westar Energy | Why not applicable to Planning Authority –<br>Response: The drafting team believes that the coordination functions of the Planning Coordinator/Planning Authority do not apply here. CBM is the import capability of the local system to serve local needs. The Planning Coordinator's role is to look at broader needs, and CBM by definition is a local need. Transmission Planners may, of course, delegate this task to the Planning Coordinator.<br>– R1.4 and 4.2.1 and 4.2.2 ATC or AFC should NEVER be allowed to be less than zero.<br>Response: The drafting team has removed this language to address the commenter's concerns.<br>– R3.1 should be Planning Authority instead of Transmission Planner.<br>Response: The drafting team believes that the coordination functions of the Planning Coordinator/Planning Authority do not apply here. CBM is the import capability of the local system to serve local needs. The Planning Coordinator's role is to look at broader needs, and CBM by definition is a local need. Transmission Planners may, of course, delegate this task to the Planning Coordinator.<br>– R3.2 Every 31 days not needed for many LSEs, this is onerous -<br>Response: The drafting team has removed this requirement. |
| Response: Please see in-line responses. | |
| Western Area Power Administration | Only those that post CBM need to document it. No Western office utilizes CBM. |
| Response: The standard does not require entities that do not use CBM to document anything. | |
| Independent Electricity System Operator | In the applicability section, there is an entity - "Planned Resource Sharing Group" that is not a defined term in the latest version of the Functional Model.<br>Additionally, there are a number of changes that have been made to the draft standard which have not been vetted with the industry but instead the SDT decided to go straight to the ballots instead. Hence we decided to vote against this standard |
| Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment. | |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td>ISO New England, Inc.</td><td>The applicability section indicates a planned resource sharing group which is not a functional entity identified in the latest version of the NERC Functional Model. Therefore, this Standard is not enforceable.<br><br>Also, a number of requirements were added after the last posting which were not reposted for comments. WE believe this is a violation of the established standard development process.</td></tr>
<tr><td colspan="2">Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment.</td></tr>
<tr><td>New York Independent System Operator</td><td>The NYISO does not use CBM and interprets the revised "Applicability" provision of MOD-004 as confirming that it will not be required to have or maintain a CBMID so long as that is the case. Nevertheless, the NYISO is voting against MOD-004 for the "general" reasons specified in its response to MOD-001, namely the fact that the proposed standard is overly detailed and addresses areas that are better left to NAESB or to the individual practices of individual practices of Reliability Coordinators, Transmission Operators, Transmission Service Providers, Transmission Planners, etc.<br><br>The NYISO also agrees with the NPCC that the latest version of MOD-004 inappropriately adds a new entity, and new requirements. Both additions raise issues that should be discussed more fully in comments before they are approved by NERC.</td></tr>
<tr><td colspan="2">Response: The drafting team agrees that Transmission Service Providers not using CBM are largely exempted from the standard (with the exception of R11). However, CBM itself is a margin established for reliability purposes. To the extent entities utilize it to meet reliability objectives, it has reliability impact, and is appropriate to be included in NERC's body of reliability standards. The drafting team has modified the standard to be less prescriptive and allow for more flexibility in how the need for CBM and CBM itself is determined.<br><br>The drafting team has removed the PRSG from the standard, and is posting the standard for comment.</td></tr>
<tr><td>PJM Interconnection, L.L.C.</td><td>MOD-004 Specific Comments: The ATC MOD standards should have been sent out for comment not pre-ballot posting.<br><br>Response: The drafting team is posting the standard for comment.<br><br>The SDT recognized that there were 3 different ways of calculating ATC and wrote MOD028-1, MOD029-1, and MOD030-1 as individual standards for each method. The SDT should be consistent in its approach and develop a second standard for CBM and cover both of the existing methods.<br><br>MOD004 as written assumes individual LSEs determine their emergency generation requirements and manage them with requests to the TSP. The standard was modified to recognize aggregating LSEs termed Planned Resource Sharing Group to recognize a different method of implementing CBM. This change falls short in that requirements still exist that are unique to the LSE method such as the processing of individual requests. The standard fails to recognize that individual instances of load import emergencies may be met through other means.<br><br>A second CBM standard should be written to represent the wider implementation of CBM on a regional basis and recognize the current practices used by ISO/RTOs or other regional entities. ISOs may manage the load emergencies using remote generation within its zone. This standard assumes all LSE GCIR is from outside the TSP zone by requiring the LSE to specify the GCIR and to match the request with transmission service set aside as CBM (imported from external resources). A single approach to CBM would result in a required methodology which does not represent how operations are conducted in large parts of the system.</td></tr>
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| Entity | Comment |
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| | Response: The drafting team has modified the standard to be less prescriptive and allow for more flexibility in how the need for CBM and CBM itself is determined.<br><br>PJM believes no requirement from the set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.<br>Response: The drafting team disagrees. While the majority of the requirements have a Violation Risk Factor of "Lower," R11 and R12 deal explicitly with the requirements for approving request for Interchange that use CBM. Such requests are made in response to an EEA 2, a reliability condition. Denial of such a request can have direct reliability implications; hence, the drafting team has set the VRFs for these requirements at "medium."<br><br>Requirement 1<br>– R1.3 should not be applicable in the event that a BA manages utilization of the transmission system and manages imports in emergency conditions on behalf of LSEs.<br>Response: This sub-requirement has been deleted.<br><br>– R1.4. A statement of whether the Transmission Service Provider allows ATC or AFC to be less than zero due to CBM has no meaning outside of R4.3 and should not be an independent requirement.<br>Response: This sub-requirement has been deleted.<br><br>Requirement 3<br>– R3 The timelines specified should be superseded by PRSG agreements. Existing processes should not be modified simply to meet requirements specified by this standard when reliability shortcomings do not exist. These timelines are best left as NAESB scope.<br>–<br>Response: These requirements have largely been eliminated from the standard.<br>– R3.1.1.1 is an awkward way of saying provide monthly values if your procedures are based on a monthly process or provided yearly if it's based on a yearly paradigm. Again this should be considered NAESB scope. ISOs that find it prudent to determine CBM on a planning timeline should not be required to respond to CBM changes on a short term basis. CBM should be determined on a timeline that allows the entities to respond to a condition of insufficient import capability. Building new infrastructure requires planning several years out. CBM could be evaluated on a short term basis to be released to the market for sale but this is NAESB scope. A second CBM standard should contain requirements that recognize this planning timeline focused method, or this requirement should be removed. |

| Entity | Comment |
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| | Response: This sub-requirement has been deleted.<br><br>– R3.1.1.4 There are probabilistic methods that don't use a prescribed source for the evaluation. In ISOs the load requirements may be met by a mix of a number of generation sources several busses away. This standard should not restrict methods currently implemented that do not require the generator to be specified. Such a requirement may restrict markets and is not in line with NERC or FERC's intent in developing standards.<br>Response: This sub-requirement has been deleted.<br><br>– R3.1.2.1 This requirement recognizes there may be different implementations other than the requirement in R3.1.1. This underscores the fact that these requirements are written to achieve an objective, which is a calculated and respected CBM value verses a required process of exactly 'How' CBM must be calculated.<br>Response: This sub-requirement has been deleted.<br><br>– R3.2 In the context described above this monthly requirement is inappropriate. This requires a monthly re-evaluation of a yearly margin determined 5 years ago. If the requirement is to ensure a release of CBM to the market if the margin is not used then that is NAESB scope.<br>Response: This sub-requirement has been deleted.<br><br>Requirement 4<br>– R4 The timelines specified should not apply to entities with existing processes that determine CBM on a Planning timeframe. These timelines should be eliminated or a second CBM standard would address the appropriate timelines for such entities.<br>Response: The drafting team has modified the standard to be less prescriptive and allow for more flexibility in how the need for CBM and CBM itself is determined.<br><br>– R4.3.1, R4.3.2 This is a procedure and doesn't belong in a standard. This appears to codify a business practice regarding the treatment of a negative ATC if CBM is applied.<br>Response: This sub-requirement has been deleted.<br><br>Requirement 6<br>– R6 is inappropriate for BAs that manage emergency situations by redirecting or redispatching within their network. R6 should be eliminated.<br>Response: R6 has been greatly simplified and replaced with R7 and R8. |

| Entity | Comment |
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| | Requirement 8<br>– R8 - A BA is not required to schedule energy. A BA may manage the import of energy during load emergencies. This requirement should be modified if a second CBM standard is not written.<br>Response: The requirement has been modified to remove the word "schedule" and references to Interchange. |
| Response: Please see in-line responses. | |
| Alabama Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, it is recommended that only the LSE be applicable. There is not a PRSG function for which NERC can audit compliance. Additionally, the PRSG is a business arrangement and is not considered a reliability issue. |
| Response: The drafting team has removed the PRSG from the standard. However, the drafting team does believe entities other than the LSE are applicable. | |
| Bonneville Power Administration | The purpose statement for MOD-004 should be expanded, to describe the timeframe for which CBM is to be activated so as not to conflict with TRM, to include a statement that "CBM is to be scheduled by the Energy Deficient Entity experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher only in the hour following a generation forced outage event." |
| Response: The drafting team disagrees with this interpretation. TRM may be used within the current hour for reserve sharing, but is a margin used to respond to events. CBM may be used at any point, and for a period longer than the current hour, subject to existing scheduling rules and requirements. | |
| Consolidated Edison Co. of New York | PSRG is not an entity defined in the NERC functional Model. |
| Response: The drafting team has removed the PRSG from the standard. | |
| Dominion Resources, Inc. | In support of PJM and NPCC comments |
| Response: Please see responses to PJM and NPCC. | |
| FirstEnergy Solutions | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br>CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc.<br>FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both. |

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<tr><th>Entity</th><th>Comment</th></tr>
<tr><td></td><td>Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br><br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br><br>Response: The drafting team is posting the standard for comment.<br><br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br><br>The Planning Coordinator (PC) should replace the Transmission Planner (TP) as the applicable entity. The requirements in R5 and R7 should be the ultimate responsibility of the PC who works with his associated TP to obtain the necessary information. Per the NERC functional model, the PC "coordinates and collects data for system modeling from the Transmission Planner" and "coordinates total transfer capability with Transmission Planners".<br><br>Response: The drafting team agrees with the descriptions given from the functional model. However, we believe that the coordination functions of the Planning Coordinator do not apply here. CBM is the import capability of the local system to serve local needs. The Planning Coordinator’s role is to look at broader needs, and CBM by definition is a local need. Transmission Planners may, of course, delegate this task to the Planning Coordinator.<br><br>This standard is too prescriptive with the detail into how CBM should be calculated across all interconnections and does not take into account all the different calculation methods currently used by various entities in the industry. It is suggested that the standard be more general and that some of the information contained is better suited with a guideline document for calculating CBM.<br><br>Response: The drafting team has modified the standard to be less prescriptive and allow for more flexibility in how the need for CBM and CBM itself is determined.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Florida Municipal Power Agency</td><td>We believe this standard needs an additional commenting period.</td></tr>
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<tr><th>Entity</th><th>Comment</th></tr>
<tr><td colspan="2">Response: The drafting team is posting the standard for comment.</td></tr>
<tr><td>Georgia Power Company</td><td>We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, it is recommended that only the LSE be applicable. There is not a PRSG function for which NERC can audit compliance. Additionally, the PRSG is a business arrangement and is not considered a reliability issue</td></tr>
<tr><td colspan="2">Response: The drafting team has removed the PRSG from the standard. However, the drafting team does believe entities other than the LSE are applicable.</td></tr>
<tr><td>Gulf Power Company</td><td>We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, it is recommended that only the LSE be applicable. There is not a PRSG function for which NERC can audit compliance. Additionally, the PRSG is a business arrangement and is not considered a reliability issue.</td></tr>
<tr><td colspan="2">Response: The drafting team has removed the PRSG from the standard. However, the drafting team does believe entities other than the LSE are applicable.</td></tr>
<tr><td>Hydro One Networks, Inc.</td><td>Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighboring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained.<br>Response: The drafting team does not believe that it is necessary for all entities to implement this standard at the same time.<br><br>In addition we offer the following comments to the specific Standard MOD-004:<br>(a) Requirement 1.1 introduces the concept of an entity called the Planned Resource Sharing Group. This entity is not defined and is not currently in the approved version of the NERC Functional Model (v.3). Adding this entity raises issues for registration and compliance.<br>(b) Requirements have been introduced for the first time in this version. None of these revisions have yet been posted for comments by the industry. New requirements should not be introduced in the final version of a standard without affording the industry some opportunity to comment. This bypasses the intent of the ANSI approved NERC RS process.<br>Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Lincoln Electric System</td><td>LES agrees with the PJM and MISO recommendation that the standard needs an additional commenting period.</td></tr>
<tr><td colspan="2">Response: The drafting team is posting the standard for comment.</td></tr>
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<tr><td>MidAmerican Energy Co.</td><td>I agree with the PJM that this standard needs another commenting period.</td></tr>
<tr><td colspan="2">Response: The drafting team is posting the standard for comment.</td></tr>
<tr><td>Mississippi Power</td><td>We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, it is recommended that only the LSE be applicable. There is not a PRSG function for which NERC can audit compliance. Additionally, the PRSG is a business arrangement and is not considered a reliability issue.</td></tr>
<tr><td colspan="2">Response: The drafting team has removed the PRSG from the standard. However, the drafting team does believe entities other than the LSE are applicable.</td></tr>
<tr><td>Municipal Electric Authority of Georgia</td><td>The drafting team's response to Entergy regarding MOD-004-1 requirement 8 implies that this standard would require TSPs to furnish CBM to "entities" that never requested or funded CBM. This unreasonable interpretation is expected to cause reliability problems for LSEs that currently rely on CBM.<br><br>From the drafting team's reply some may even infer that all "entities" have an entitlement to use a TSP's CBM even if, for example, such "entities" have no transmission service contract with the TSP or such "entities" are insolvent. An obvious alternative interpretation, consistent with the terminology used in requirement 10, is that TSPs may reasonably conclude that CBM is not AVAILABLE to entities that have not made a valid CBM request (except to extent CBM capacity is released and purchased non-firm).<br><br>Response: The drafting team has modified the standard to address this concern by only requiring a TSP to approve the transaction if the EEA 2 for which the CBM is being scheduled is within the Transmission Service Providers area. Issues related to creditworthiness are not within the scope of NERC.<br><br>Furthermore, the drafting team's interpretation raises questions not envisioned when we conducted our review of the draft standard. For example, the standard is silent on whether a TSP may prioritize competing requests to use CBM. Is the CBM first come, first served without any consideration of whether the requestor complied with the TSP's CBMID<br>– If an LSE that reserved CBM loses a generator after all the CBM is in use by other "entities" that never requested CBM, does the TSP deny CBM to the LSE that requested and paid for it?<br><br>Undoubtedly, if FERC approves this standard without changes, it would have to raise questions if the drafting team's interpretation comports with the Takings Clause of the Fifth Amendment to the U.S. Constitution.<br><br>Response: The drafting team believes that determinations such as those described are best left to business practices, as they are commercial in nature and deals primarily with equity between LSEs, rather than reliability. For this reason, the team took no position on the issue, and only required that use of CBM be approved if available – not denied if unavailable.<br><br>Finally, while some may argue that the drafting team's interpretation will improve reliability for customers of systems that are short on installed capacity (and this may be the case in the short-run), the unintended consequence is that entities that may already be irresponsibly under-resourced may further reduce their installed capacity investments once they learn they can free ride on their neighbors' CBM.</td></tr>
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| Entity | Comment |
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| | Response: The drafting team has modified the standard to address this concern by only requiring a TSP to approve the transaction if the EEA 2 for which the CBM is being scheduled is within the Transmission Service Providers area. |
| Response: Please see in-line responses. | |
| New York Power Authority | MOD-004-1--recommendation to vote NO not to accept. NPCC RSC found problems with the applicability section as it pertains to the planned resource sharing group. Requirement 1.1 adds this concept of an entity called the Planned Resource Sharing Group. This entity is not defined and is not currently in the latest approved version of the NERC Functional Model (v.3). Adding this entity raises issues for registration and compliance.<br>Additionally, requirements have been introduced for the first time in this version. None of these revisions have yet been circulated for comment. New requirements should not be introduced in the final version of a standard without affording the industry some opportunity to comment. This, in the view of the RSC bypasses the intent of the ANSI approved NERC RS process. |
| Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment. | |
| PECO Energy an Exelon Co. | R1.5. A statement should be added to confirm that it shall use assumptions in calculating CBM that are consistent with those assumptions that are used in the Transmission planning process. |
| Response: The drafting team believes that CBM can be based on studies and requirements outside the scope of the Transmission planning process defined in the TPL standards. | |
| Public Service Electric and Gas Co. | PSE&G votes NO for the reasons expressed in PJM's comments. |
| Response: Please see response to PJM. | |
| Santee Cooper | The drafting team's response to Entergy regarding MOD-004-1 Requirement 8 implies that this standard would require a Transmission Service Provider to furnish CBM to any LSE or "entity" that never requested or funded CBM. Another unintended consequence of Requirement 8 is that entities (some that may already be irresponsibly under-resourced) may further reduce their installed capacity investments once they learn they can free ride on their neighbors' CBM. |
| Response: The drafting team has modified the standard to address this concern by only requiring a TSP to approve the transaction if the EEA 2 for which the CBM is being scheduled is within the Transmission Service Providers area. | |
| Wisconsin Electric Power Marketing | GCIR definition - We are uncomfortable with the definition of GCIR, especially with no guidance on the determination or use of this quantity. Additionally it is not specified whether this is a maximum or average over the period in question.<br>Response: The definition provides a general explanation of what GCIR is. R3 and R4 describe options for its calculation. It is expected that Transmission Service Providers or others may develop business practices that describe in more detail how GCIR is to be determined and/or used.<br><br>PRSG definition - The definition states that this is an agreement to jointly meet a resource adequacy requirement, there are some PRSG's that are just doing a "joint study" to determine a requirement but how they meet that requirement may be |

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| | unique to the LSE.<br>Response: The drafting team has removed the definition.<br><br>R4.1.2 - The determination of the CBM seems to be disconnected from the current resource adequacy methodology processes that are being used in most RTO's. I.e. a difference in models could induce inconsistencies in the CBM that is actually available and the reserve margins identified in the resource adequacy studies.<br>Response: The drafting team has modified the standard to be less prescriptive, allowing more flexibility for entities with regional processes for determining CBM, such as RTOs.<br><br>R4.3 - It is difficult to tell whether the process is a "first come first served" process or whether all CBM requests are evaluated on a common basis.<br>Response: The drafting team believes that determinations such as those described are best left to business practices, as they are commercial in nature and deals primarily with equity between LSEs, rather than reliability. For this reason, the team took no position on the issue, and only required that use of CBM be approved if available – not denied if unavailable.<br><br>R7 - There should be a consideration to providing these studies to LSE's to assist in coordination of methodologies etc.<br>Response: The drafting team believes that NAESB is the appropriate forum to develop business practices related to transparency and commercial needs.<br><br>Measures, M3 - The words "that wants CBM" could be better stated as "is requesting CBM to support the calculated reserve margin"<br>Response: The drafting team has modified the language to eliminate the phrase “that wants CBM,” and replaced it with “Each Load-Serving Entity that determined a need for Transmission Capacity to be set aside as CBM” |
| Response: Please see in-line responses. | |
| Wisconsin Public Service Corp. | WPSC agrees with the PJM and MISO recommendation that the standard needs an additional commenting period . |
| Response: The drafting team is posting the standard for comment. | |
| Florida Municipal Power Agency | We believe this standard needs an additional commenting period. |
| Response: The drafting team is posting the standard for comment. | |
| Madison Gas | We agree with the PJM and MISO recommendation that the standard needs an additional commenting period . |

| Entity | Comment |
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| and Electric Co. | |
| Response: The drafting team is posting the standard for comment. | |
| Wisconsin Energy Corp. | GCIR definition - We are uncomfortable with the definition of GCIR, especially with no guidance on the determination or use of this quantity. Additionally it is not specified whether this is a maximum or average over the period in question.<br>The definition provides a general explanation of what GCIR is. R3 and R4 describe options for its calculation. It is expected that Transmission Service Providers or others may develop business practices that describe in more detail how GCIR is to be determined and/or used.<br><br>PRSG definition - The definition states that this is an agreement to jointly meet a resource adequacy requirement, there are some PRSG's that are just doing a "joint study" to determine a requirement but how they meet that requirement may be unique to the LSE.<br>Response: The drafting team has removed the definition.<br><br>R4.1.2 - The determination of the CBM seems to be disconnected from the current resource adequacy methodology processes that are being used in most RTO's. I.e. a difference in models could induce inconsistencies in the CBM that is actually available and the reserve margins identified in the resource adequacy studies.<br>Response: The drafting team has modified the standard to be less prescriptive, allowing more flexibility for entities with regional processes for determining CBM, such as RTOs.<br><br>R4.3 - It is difficult to tell whether the process is a "first come first served" process or whether all CBM requests are evaluated on a common basis.<br>Response: The drafting team believes that determinations such as those described are best left to business practices, as they are commercial in nature and deals primarily with equity between LSEs, rather than reliability. For this reason, the team took no position on the issue, and only required that use of CBM be approved if available – not denied if unavailable.<br><br>R7 - There should be a consideration to providing these studies to LSE's to assist in coordination of methodologies etc.<br>Response: The drafting team believes that NAESB is the appropriate forum to develop business practices related to transparency and commercial needs.<br><br>Measures, M3- The words "that wants CBM" could be better stated as "is requesting CBM to support the calculated reserve margin"<br>Response: The drafting team has modified the language to eliminate the phrase “that wants CBM,” and replaced it with “Each Load-Serving Entity that determined a need for Transmission Capacity to be set aside as CBM” |
| Response: Please see in-line responses. | |

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| WPS Resources Corp. | Standard MOD-004 is confusing in that it mixes the use of Generation Capability Import Requirement (GCIR) and CBM. If GCIR and CBM are intended to reflect different quantities, the standard should provide a definition for CBM. The standard needs to clearly reference GCIR and CBM throughout the document, consistent with their definitions.<br>Response: The definition of CBM currently exists in the NERC glossary, and the drafting team is not suggesting modification to that definition. We have reviewed the standard to use these terms consistently.<br><br>The definition of PRSG should reflect the intent of a PRSG - to collectively assess the resource adequacy of a group of LSEs. The current definition inappropriately refers to a "resource adequacy requirement" which EPAct 2005 prohibits FERC and the ERO from establishing. Also, the current definition suggests a sharing of "planned resources" rather than a sharing of "planning reserves". Suggest the following definition for PRSG (consistent with MRO's approved Resource Adequacy Assessment standard): Planned Reserve Sharing Group ("PRSG") is defined as a group of Load Serving Entities ("LSEs") that agree to study their collective resources to assess the planned Resource Adequacy for the load of the PRSG as a whole.<br>Response: The drafting team has eliminated this definition, and believes that it is not necessary to specify the structure of any JRO beyond that which is defined in the registration process.<br><br>R2 - the CBMID should be made available to everyone, not just TOs, TPs, RCs, and transmission planners. In order to provide for transparency and consistency, the CBM Implementation Document should be available to all users, owners, and operators of the transmission system.<br>Response: The drafting team believes that NAESB is the appropriate forum to develop business practices related to transparency and commercial needs.<br><br>R7 - same comment as R2 - the allocation of CBM over different ATC/AFC paths must be available to all users, owners, and operators.<br>Response: The drafting team believes that NAESB is the appropriate forum to develop business practices related to transparency and commercial needs.<br><br>Requirement R3.1.2 references entities that do not have the ability to establish resource adequacy assessment requirements. Only the Regional Entities, through their ANSI approved standards setting process and delegated authority, can establish requirements for resource adequacy assessment. R3.1.2 should refer to FERC approved standards only.<br>Response: The drafting team disagrees. REs are not the only entities that can establish resource adequacy assessment criteria. FERC has also indicated in Order 890 that is believes other entities have the ability to establish these criteria.<br><br>R3.3 The request for CBM should be based on the resource adequacy assessment criteria of the REs only. Only the REs have the ANSI accredited processes and delegated authority to establish resource adequacy assessment criteria.<br>Response: The drafting team disagrees. REs are not the only entities that can establish resource adequacy assessment |

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| | criteria. FERC has also indicated in Order 890 that is believes other entities have the ability to establish these criteria.<br><br>R4.2.1 and R4.3.1 - both of these requirements allow the TP to unilaterally reduce the CBM requested by LSEs. While TPs should have the ability to post negative ATC/AFC as zero, the TP should not have the right to reduce the CBM of the LSEs.<br>Response: The drafting team has eliminated this requirement. The drafting team has modified the standard to be less prescriptive and allow for more flexibility in how the need for CBM and CBM itself is determined.<br><br>M5 refers to "regional generation reliability criteria". Generation reliability criteria are different than resource adequacy assessment criteria. M5 should only reference the later.<br>Response: M5 has been modified and no longer includes this reference. |
| Response: Please see in-line responses. | |
| Bonneville Power Administration | The purpose statement for MOD-004 should be expanded, to describe the timeframe for which CBM is to be activated so as not to conflict with TRM, to include a statement that "CBM is to be scheduled by the Energy Deficient Entity experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher only in the hour following a generation forced outage event." |
| Response: The drafting team disagrees with this interpretation. TRM may be used within the current hour for reserve sharing, but is a margin used to respond to events. CBM may be used at any point, and for a period longer than the current hour, subject to existing scheduling rules and requirements. | |
| Calpine Corporation | The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose.<br>Response: The drafting team believes that NAESB is the appropriate forum to develop business practices related to transparency and commercial needs.<br><br>We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency.<br>Response: The drafting team believes that NAESB is the appropriate forum to develop business practices related to transparency and commercial needs. NERC will work with NAESB to ensure that in future ballots and postings, entities are made more aware of the division of labor and coordination effort.<br><br>The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document, is difficult to evaluate if it is not yet determined which parties will have access to the document. |

| Entity | Comment |
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| | Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization. While TSPs are presumably expected to specify this in their CBMID, it should not be left to individual TSPs to determine that when CBM is requested beyond the existing capability of the system, such requests cannot take precedence over rollover rights previously granted to transmission customers.<br><br>Response: The drafting team believes that determinations such as those described are best left to business practices, as they are commercial in nature and deals primarily with equity between LSEs, rather than reliability. For this reason, the team took no position on the issue, and only required that use of CBM be approved if available – not denied if unavailable. |
| Response: Please see in-line responses. | |
| Electric Power Supply Association | Greater transparency is required for the CBMID. This can be achieved through the use of a single document with a comprehensive list of assumptions that improves the status quo. The document should be accessible by all market participants to ensure its utility. The document needs to be flexible enough to have applicability across jurisdictions so that assumptions are captured in the CBMID but not in a manner that undermines market participants having sufficient standardization. While TSPs are presumably expected to specify this in their CBMID, it should not be left to individual TSPs to determine that when CBM is requested beyond the existing capability of the system, such requests cannot take precedence over rollover rights previously granted to transmission customers. |
| Response: The drafting team believes that NAESB is the appropriate forum to develop business practices related to transparency and commercial needs. NERC will work with NAESB to ensure that in future ballots and postings, entities are made more aware of the division of labor and coordination effort.<br><br>The drafting team believes that determinations such as those described are best left to business practices, as they are commercial in nature and deals primarily with equity between LSEs, rather than reliability. For this reason, the team took no position on the issue, and only required that use of CBM be approved if available – not denied if unavailable. | |
| FirstEnergy Solutions | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br><br>CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc.<br><br>FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both.<br><br>Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br><br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many |

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| | cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br>Response: The drafting team is posting the standard for comment.<br><br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>– The Planning Coordinator (PC) should replace the Transmission Planner (TP) as the applicable entity.<br>– The requirements in R5 and R7 should be the ultimate responsibility of the PC who works with his associated TP to obtain the necessary information. Per the NERC functional model, the PC "coordinates and collects data for system modeling from the Transmission Planner" and "coordinates total transfer capability with Transmission Planners".<br>Response: The drafting team agrees with the descriptions given from the functional model. However, we believe that the coordination functions of the Planning Coordinator do not apply here. CBM is the import capability of the local system to serve local needs. The Planning Coordinator's role is to look at broader needs, and CBM by definition is a local need. Transmission Planners may, of course, delegate this task to the Planning Coordinator.<br><br>– This standard is too prescriptive with the detail into how CBM should be calculated across all interconnections and does not take into account all the different calculation methods currently used by various entities in the industry. It is suggested that the standard be more general and that some of the information contained is better suited with a guideline document for calculating CBM.<br>Response: The drafting team has modified the standard to be less prescriptive and allow for more flexibility in how the need for CBM and CBM itself is determined. |
| Response: Please see in-line responses. | |
| Florida Municipal Power Agency | We believe this standard needs an additional commenting period. |
| Response: The drafting team is posting the standard for comment. | |
| Lincoln Electric System | LES agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |

| Entity | Comment |
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| Response: The drafting team is posting the standard for comment. | |
| PSEG Power LLC | PSEG Power LLC votes no for the reasons expressed in PJM's comments. |
| Response: Please see response to PJM. | |
| Wisconsin Electric Power Co. | GCIR definition - We are uncomfortable with the definition of GCIR, especially with no guidance on the determination or use of this quantity. Additionally it is not specified whether this is a maximum or average over the period in question.<br>The definition provides a general explanation of what GCIR is. R3 and R4 describe options for its calculation. It is expected that Transmission Service Providers or others may develop business practices that describe in more detail how GCIR is to be determined and/or used.<br><br>PRSG definition - The definition states that this is an agreement to jointly meet a resource adequacy requirement, there are some PRSG's that are just doing a "joint study" to determine a requirement but how they meet that requirement may be unique to the LSE.<br>Response: The drafting team has removed the definition.<br><br>R4.1.2 - The determination of the CBM seems to be disconnected from the current resource adequacy methodology processes that are being used in most RTO's. I.e. a difference in models could induce inconsistencies in the CBM that is actually available and the reserve margins identified in the resource adequacy studies.<br>Response: The drafting team has modified the standard to be less prescriptive, allowing more flexibility for entities with regional processes for determining CBM, such as RTOs.<br><br>R4.3 - It is difficult to tell whether the process is a "first come first served" process or whether all CBM requests are evaluated on a common basis.<br>Response: The drafting team believes that determinations such as those described are best left to business practices, as they are commercial in nature and deals primarily with equity between LSEs, rather than reliability. For this reason, the team took no position on the issue, and only required that use of CBM be approved if available – not denied if unavailable.<br><br>R7 - There should be a consideration to providing these studies to LSE's to assist in coordination of methodologies etc.<br>Response: The drafting team believes that NAESB is the appropriate forum to develop business practices related to transparency and commercial needs.<br><br>Measures, M3 - The words "that wants CBM" could be better stated as "is requesting CBM to support the calculated reserve margin"<br>Response: The drafting team has modified the language to eliminate the phrase "that wants CBM," and replaced it with "Each |

| Entity | Comment |
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| | Load-Serving Entity that determined a need for Transmission Capacity to be set aside as CBM” |
| Response: Please see in-line responses. | |
| Barry Green Consulting Inc. | Transparency: The former NERC standard for ATC required only that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-004 that is being balloted, the word "transparency" has been deleted from the purpose.<br>Response: The drafting team believes that NAESB is the appropriate forum to develop business practices related to transparency and commercial needs.<br><br>We also note that the standard requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency.<br>Response: The drafting team believes that NAESB is the appropriate forum to develop business practices related to transparency and commercial needs.  NERC will work with NAESB to ensure that in future ballots and postings, entities are made more aware of the division of labor and coordination effort.<br><br>The notion of a CBMID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document, is difficult to evaluate if it is not yet determined which parties will have access to the document.<br>Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the CBMID cannot assure market participants of a sufficient degree of standardization. In addition, while TSPs are presumably expected to specify this in their CBMID, it should not be left to individual TSPs to determine that when CBM is requested beyond the existing capability of the system, such requests cannot take precedence over rollover rights previously granted to transmission customers.<br>Response: The drafting team believes that determinations such as those described are best left to business practices, as they are commercial in nature and deals primarily with equity between LSEs, rather than reliability.   For this reason, the team took no position on the issue, and only required that use of CBM be approved if available – not denied if unavailable. |
| Response: Please see in-line responses. | |
| Bonneville Power Administration | The purpose statement for MOD-004 should be expanded, to describe the timeframe for which CBM is to be activated so as not to conflict with TRM, to include a statement that "CBM is to be scheduled by the Energy Deficient Entity experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher only in the hour following a generation forced outage event." |
| Response:  The drafting team disagrees with this interpretation.  TRM may be used within the current hour for reserve sharing, but is a margin used to respond to events.  CBM may be used at any point, and for a period longer than the current hour, subject to existing scheduling rules | |

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| and requirements. | |
| Consolidated Edison Co. of New York | PSRG is not an entity defined in the NERC functional Model. |
| Response: The drafting team has removed the PRSG from the standard. | |
| Dominion Resources, Inc. | Support comments provided by NPCC and PJM |
| Response: Please see responses to NPCC and PJM. | |
| FirstEnergy Solutions | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>The Planning Coordinator (PC) should replace the Transmission Planner (TP) as the applicable entity.<br>The requirements in R5 and R7 should be the ultimate responsibility of the PC who works with his associated TP to obtain the necessary information. Per the NERC functional model, the PC "coordinates and collects data for system modeling from the Transmission Planner" and "coordinates total transfer capability with Transmission Planners".<br>This standard is too prescriptive with the detail into how CBM should be calculated across all interconnections and does not take into account all the different calculation methods currently used by various entities in the industry. It is suggested that the standard be more general and that some of the information contained is better suited with a guideline document for calculating CBM. |
| Response: The drafting team agrees with the descriptions given from the functional model. However, we believe that the coordination functions of the Planning Coordinator do not apply here. CBM is the import capability of the local system to serve local needs. The Planning Coordinator's role is to look at broader needs, and CBM by definition is a local need. Transmission Planners may, of course, delegate this task to the Planning Coordinator.<br><br>The drafting team has modified the standard to be less prescriptive and allow for more flexibility in how the need for CBM and CBM itself is determined. | |
| Lincoln Electric System | LES agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The drafting team and is posting the standard for comment. | |
| MidAmerican Energy Co. | Although this standard leaves much to be desired, it is better than the current standard. I hope NERC continues to work towards consistency in the arena of CBM. |
| Response: Thank you. The drafting team will continue to work to achieve this goal. | |
| PSEG Energy Resources & | PSEG Energy Resources & Trade votes NO for the reasons expressed in PJM's ballot. |

| Entity | Comment |
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| Trade LLC | |
| Response: Please see response to PJM. | |
| Santee Cooper | The drafting team's response to Entergy regarding MOD-004-1 Requirement 8 implies that this standard would require a Transmission Service Provider to furnish CBM to any LSE or "entity" that never requested or funded CBM. Another unintended consequence of Requirement 8 is that entities (some that may already be irresponsibly under-resourced) may further reduce their installed capacity investments once they learn they can free ride on their neighbors' CBM. |
| Response: The drafting team has modified the standard to address this concern by only requiring a TSP to approve the transaction if the EEA2 for which the CBM is being scheduled is within the Transmission Service Providers area. | |
| Commonwealth of Massachusetts Department of Public Utilities | Massachusetts DPU found problems with the applicability section as it pertains to the planned resource sharing group. Requirement 1.1 adds this concept of an entity called the Planned Resource Sharing Group. This entity is not defined and is not currently in the latest approved version of the NERC Functional Model (v.3). Adding this entity raises issues for registration and compliance.<br>Requirements have been introduced for the first time in this version. None of these revisions have yet been circulated for comment. New requirements should not be introduced in the final version of a standard without affording the industry some opportunity to comment. This appears to bypass approved NERC RS process. |
| Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment. | |
| National Association of Regulatory Utility Commissioners | Due to the extensive revisions in the final draft, industry input should have been solicited before setting this revised standard for a vote. |
| Response: The drafting team is posting the standard for comment. | |
| Wyoming Public Service Commission | Should not prevent the inclusion of intermittent resources if they exhibit sufficient diversity and can be successfully integrated. |
| Response: The drafting team does not believe the scope of this standard addresses specific types of resources. If the Commission has specific concerns with the language, please provide more detail regarding how you believe the language should be modified. | |
| Midwest Reliability Organization | The MRO agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The drafting team is posting the standard for comment. | |
| Northeast Power | A new entity, a Planned Resource Sharing Group, that is not identified in the functional model, is included. A re-posting of the standard is recommended to allow for industry comments. |

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| Coordinating Council, Inc. | |
| Response: The drafting team has removed the PRSG from the standard, and is posting the standard for comment. | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC Authorized posting TTC/ATC/AFC SAR Development June 20 2005.
2. SAC Authorized the SAR to be development as a standard on February 14 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from February 15–March 16, 2007.
5. SDT posted second draft for comment from May 25–June 25, 2007.
6. SDT posted third draft for comment from October 31–December 15, 2007.

**Description of Current Draft:**

This is the fourth and final draft of the proposed standard posted for stakeholder comments. This draft represents consideration of stakeholder comments submitted with the third draft of the proposed revisions to MOD-001 as well as consideration of applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**ATC Path:** Any combination of Point of Receipt and Point of Delivery for which ATC is calculated.

**Available Transfer Capability Implementation Document (ATCID):** A document that describes the implementation of an Available Transfer Capability methodology.

**Transmission Operator Area:** The collection of Transmission assets over which the Transmission Operator is responsible for operating.

**Existing Transmission Commitments (ETC):** Committed uses of a Transmission Service Provider's Transmission system considered when determining Available Transfer Capability.

**Planning Coordinator:** See Planning Authority.

**Postback:** Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

**Business Practices:** Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization business practices; or NAESB Business Practices**.**

**Block Dispatch:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

**Dispatch Order:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

**Participation Factors:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

## A. Introduction

1. **Title:** **Available Transfer Capability**

2. **Number:** **MOD-001-1**

3. **Purpose:** To promote the consistent and reliable application and documentation of Available Transfer Capability (ATC) calculations for analysis and system operations.

4. **Applicability:**

   **4.1.** Transmission Service Provider.

   **4.2.** Transmission Operator.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall select one ATC methodology[1] (Area Interchange methodology, Rated System Path methodology, or Flowgate methodology) for each ATC Path per time period identified in R2 for use in determining Transfer Capabilities of those Facilities within its Transmission operating area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R2.** Each Transmission Service Provider shall calculate ATC values as listed below using the ATC methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Hourly ATC values for at least the next 168 hours.

**R2.2.** Daily ATC values for at least the next 31 calendar days.

**R2.3.** Monthly ATC values for at least the next 12 months (months 2-13).

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC calculations can be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows including:

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[1] All ATC Paths do not have to use the same ATC Methodology and no particular ATC Path must use the same ATC Methodology for all time periods.

**R3.2.1.** How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC calculations.

**R3.2.2.** A rationale for the defined accounting.

**R3.3.** The identity of the Transmission Operators from which the Transmission Service Provider receives data for use in calculating ATC.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer capability.

**R3.5.** The identity of the Transmission Service Providers from which it receives data for use in calculating transfer capability.

**R3.6.** A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate Transfer Capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate Transfer Capabilities among multiple owners or users of a single path or Flowgate.
- Processes used to allocate AFC between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

**R3.7.** A description of how outage durations are considered in ATC calculations, including:

**R3.7.1.** The criteria used to determine when an outage impacts a daily ATC calculation.

**R3.7.2.** The criteria used to determine when an outage impacts a monthly ATC calculation.

**R4.** The Transmission Service Provider shall notify the following entities (via electronic mail) before implementing a new or revised ATCID: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

**R4.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

**R4.3.** Each Transmission Operator associated with the Transmission Service Provider's area.

**R4.4.** Each Planning Coordinator adjacent to the Transmission Service Provider's area.

**R4.5.** Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

**R4.6.** Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

**R5.** The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.** When calculating TTC, AFC and ATC, the Transmission Operator and Transmission Service Provider shall each use assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.** Each Transmission Service Provider shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.1.** For hourly ATC, once per hour.

**R7.2.** For daily ATC, once per day.

**R7.3.** For monthly ATC, once a week.

**R8.** Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below for use in ATC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R8.1 and R8.2: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Confirmed firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.

- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), and TTC for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

**R8.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

**R8.2.** This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one or more of the specified ATC methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator's operating area. (R1).

**M2.** The Transmission Service Provider shall provide ATC values and identification of the selected ATC methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 168 hours of hourly ATC values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily ATC values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly ATC values calculated at all times (Months 2–13). (R2.3)

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** The Transmission Service Provider shall provide evidence (such as dated electronic mail messages) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

**M5.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

**M6.** The Transmission Service Provider and Transmission Operator shall each provide a copy of the assumptions (such as loop flow, generation re-dispatch, switching operating guides, load shedding or data sources for load forecast and facility outages) used to calculate TTC, ATC and AFC as well as other evidence (such as copies of operations and planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC, ATC, and AFC were consistent with those used in operations or planning studies for the time period studied. (R6)

**M7.** The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly ATC on at least the minimum frequencies specified in R7 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R7)

**M8.** The Transmission Service Provider shall provide a copy of the dated request for ATC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R8. (R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.

- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Operator did not select one or more of the specified methodologies. |
| R2. | N/A | N/A | N/A | The Transmission Service Provider did not calculate ATCs based on the time periods in R2.<br>**OR**<br>Did not use the selected methodology(ies) to calculate ATC. |
| R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>**OR**<br>The Transmission Service Provider has an ATCID, but it does not include two or more of the information items described in R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>**OR**<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include any of the information described in R3. |
| R4. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 14, but not more than 30, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation. | The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in R5 |
| R6. | N/A | N/A | N/A | The Transmission Service Provider or Transmission Operator did not determine ATC using assumptions consistent with those used in planning or operations studies for the studied time period. |
| R7. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 12 hours but not more than 15 hours,<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 2 calendar days but not more than 3 calendar days,<br>**OR**<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 8 or more calendar days, but less than 14 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours,<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days,<br>**OR**<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours,<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days,<br>**OR**<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours,<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days,<br>**OR**<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R8 | N/A | The Transmission Service Provider made the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available more than 30 calendar days but less than 45 calendar days after receiving a request. | The Transmission Service Provider made the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available 45 calendar days or more but less than 60 calendar days after receiving a request. | The Transmission Service Provider did not make the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available for 60 calendar days or more after receiving a request. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC Authorized posting TTC/ATC/AFC SAR Development June 20 2005.
2. SAC Authorized the SAR to be development as a standard on February 14 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from February 15–March 16, 2007.
5. SDT posted second draft for comment from May 25–June 25, 2007.
6. SDT posted third draft for comment from October 31–December 15, 2007.

**Description of Current Draft:**

This is the fourth and final draft of the proposed standard posted for stakeholder comments. This draft represents consideration of stakeholder comments submitted with the third draft of the proposed revisions to MOD-001 as well as consideration of applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. First ballot of standard. | March 7, 2008 |
| 2. Respond to comments. | April 22, 2008 |
| 3. Recirculation ballot. | April 22, 2008 |
| 4. 30-day posting before board adoption. | March 7, 2008 |
| 5. Board adoption. | May 5, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

~~**Posted Path:**~~

~~1)Any Balancing Authority to Balancing Authority interconnection;~~

~~2)Any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months;~~

~~3)Any path for which a Transmission Customer requests to have Available Transfer Capability or Total Transfer Capability posted.~~

**ATC Path:** Any combination of Point of Receipt and Point of Delivery for which ATC is calculated.

**Available Transfer Capability Implementation Document (ATCID):** A document that describes the implementation of an Available Transfer Capability methodology.

**Transmission Operator Area:** The collection of Transmission assets over which the Transmission Operator is responsible for operating.

**Existing Transmission Commitments (ETC):** Committed uses of a Transmission Service Provider's Transmission system considered when determining Available Transfer Capability.

**Planning Coordinator:** See Planning Authority.

**Postback:** Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

**Business Practices:** Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization business practices; or NAESB Business Practices.

**Block Dispatch:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

**Dispatch Order:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

**Participation Factors:** A simplification of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

## A. Introduction

1. **Title:** **Available Transfer Capability**

2. **Number:** **MOD-001-1**

3. **Purpose:** To promote the consistent and ~~transparent~~ reliable application and documentation of Available Transfer Capability (ATC) calculations for ~~reliable~~ analysis and system operations.

4. **Applicability:**

   **4.1.** Transmission Service Provider.

   **4.2.** Transmission Operator.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that ~~all six (~~MOD-001-1, ~~MOD-004-1, MOD-008-1,~~ MOD-028-1, MOD-029-1, and MOD-030-1~~)ATC-related standards~~ are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall select one ATC methodology[1] (Area Interchange methodology, Rated System Path methodology, or Flowgate methodology) for each ~~Posted~~ ATC Path per time period identified in R2 for use in determining Transfer Capabilities of those Facilities within its Transmission ~~Planning Coordinator's planning~~operating area. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.** Each Transmission Service Provider shall calculate ATC values ~~for the time periods~~as listed below using the ~~selected~~ ATC methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**R2.1.** Hourly ATC values for at least the next 168 hours.

**R2.2.** Daily ATC values for at least the next 31 calendar days.

**R2.3.** Monthly ATC values for at least ~~the current month plus~~ the next 12 months (months 2-13).

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC calculations ~~may~~ can be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows ~~or counter-schedules~~including:

**R3.2.1.** How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC calculations.

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[1] All ~~Posted~~ ATC Paths do not have to use the same ATC Methodology and no particular ~~Posted~~ ATC Path must use the same ATC Methodology for all time periods.

**R3.2.2.** A rationale for the defined accounting.

**R3.3.** The identity of the ~~Planning Coordinator and~~ Transmission Operators ~~associated with each Facility under the Transmission Service Provider's tariff~~from which the Transmission Service Provider receives data for use in calculating ATC.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer capability.

**R3.5.** The identity of the Transmission Service Providers from which it receives data for use in calculating transfer capability.

**R3.6.** A description of the a~~A~~llocation ~~methodologies~~processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate Transfer Capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate Transfer Capabilities among multiple owners or users of a single path or Flowgate.
- Processes used to allocate AFC between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

**R3.7.** A description of how outage durations are considered in ATC calculations, including:

**R3.7.1.** The criteria used to determine when an outage impacts a daily ATC calculation.

**R3.7.2.** The criteria used to determine when an outage impacts a monthly ATC calculation.

~~**R4.**When determining the impact of counterflows in the determination of firm ATC or AFC, the Transmission Service Provider shall use 0% of calculated counterflows based on reservations and/or schedules unless otherwise specified within the Transmission Service Provider's ATCID. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]~~

~~**R5.**When determining the impact of counterflows in the determination of non-firm ATC or Available Flowgate Capability (AFC), the Transmission Service Provider shall apply the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]~~

~~**R5.1.**Use 0% of calculated counterflows based on reservations unless otherwise specified within the Transmission Service Provider's ATCID.~~

~~**R5.2.**Use 100% of calculated counterflows based on schedules unless otherwise specified within the Transmission Service Provider's ATCID.~~

**~~R6.~~R4.** The Transmission Service Provider shall notify the following entities (via electronic mail) before implementing a new or revised ATCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**~~R6.1.~~R4.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

**~~R6.2.~~R4.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

~~R6.3.~~R4.3. Each Transmission Operator associated with the Transmission Service Provider's area.

~~R6.4.~~R4.4. Each Planning Coordinator adjacent to the Transmission Service Provider's area.

~~R6.5.~~R4.5. Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

~~R6.6.~~R4.6. Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

~~R7.~~R5. The Transmission Service Provider shall make available the current ATCID ~~and any changes to the ATCID~~ to all of the entities specified in ~~R6~~R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~R8.~~R6. When calculating ~~Total Transfer Capability (~~TTC~~)~~, AFC and ATC, the Transmission Operator and Transmission Service Provider shall each use assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~R9.~~R7. Each Transmission Service Provider shall ~~update~~ recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

~~R9.1.~~R7.1. For hourly ATC, once per hour.

~~R9.2.~~R7.2. For daily ATC, once per day.

~~R9.3.~~R7.3. For monthly ATC, once a week.

~~R10.~~R8. Within ~~fourteen~~ thirty calendar days of receiving a request ~~of~~ by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below for use in ATC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R8.1 and R8.2:~~available on the schedule specified by the requester (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider), unless another request already specifies data on a more frequent basis, to each requester, current versions of the following data as requested in electronic format for use in ATC calculations, for up to 13 months into the future (subject to confidentiality and security requirements):~~ *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- ~~P10.1.~~ Expected generation and Transmission outages, additions, and retirements.
- ~~P10.2.~~ ~~Peak~~ Load forecasts.
- ~~P10.3.~~ Unit commitments and ~~dispatch~~ order~~s~~ of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch O~~o~~rder
  - Participation F~~f~~actors
  - Block D~~d~~ispatch

- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (~~i.e~~i.e. Secondary Service).
- ~~Firm and non-firm Network Integration Transmission Service details.~~

~~P10.5.~~ Confirmed firm and non-firm Transmission reservations.

- Aggregated capacity set-aside for Grandfathered obligations
- ~~Grandfathered firm and non-firm contracted transmission capacity on an aggregated basis.~~

~~P10.7.~~ Firm roll-over rights.

~~P10.8.~~ Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.

~~P10.9.~~ Power flow models and underlying assumptions.

~~P10.10.~~ Contingencies, provided in one or more of the following formats:

- A list of Elements
- A list of Flowgates
- A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider

~~P10.11.~~ Facility Ratings.

- Any other services that impact Existing Transmission Commitments (ETCs).
- ~~Counterflows.~~

~~P10.13.~~ Values of ~~ATC, ETC,~~ Capacity Benefit Margin (CBM~~),~~) and Transmission Reliability Margin (TRM), and TTC for all ~~Posted~~ ATC Paths or Flowgates.

~~P10.14.~~ Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.

- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.

~~P10.15.~~ Source and sink identification and mapping to the model.

**R8.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, -for up to 13 months into the future (subject to confidentiality and security requirements).

**R8.2.** This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one or more of the specified ATC methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ~~Posted~~ ATC Path within the ~~Planning Coordinator's planning~~Transmission Operator's operating area. (R1).

**M2.** The Transmission Service Provider shall provide ATC values and identification of the selected ATC methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC for the following using the selected methodology or methodologies chosen as part of R1 (R2~~1~~):

- There has been at least 168 hours of hourly ATC values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily ATC values calculated at all times. (R2.2)
- There has been at least the next 12 months ~~plus the current month~~ of monthly ATC values calculated at all times (Months 2-13). (R2.3)

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** ~~The Transmission Service Provider shall provide its ATCID and other evidence (such as documentation and data) to show that it determined counterflows based on the rules in R4 and R5. (R4) (R5)~~

~~**M5.**~~ The Transmission Service Provider shall provide evidence (such as ~~copies of its~~ dated electronic mail messages) ~~used to make notifications in accordance with R6 as evidence~~ that it has notified the entities specified in ~~R5~~ R4 before a new or revised ATCID was implemented. (~~R6~~R4)

**~~M6~~M5.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in ~~R6~~R4, as required by ~~R7~~R5. (~~R7~~R5)

**~~M7~~M6.** The Transmission Service Provider and Transmission Operator shall each provide a copy of the assumptions (such as loop flow, generation re-dispatch, switching operating guides, load shedding or data sources for load forecast and facility outages) used to calculate TTC, ATC and AFC as well as ~~copies of operations and planning studies and~~ other evidence (such as copies of operations and planning studies, ~~written documentation,~~ models, ~~studies,~~ supporting information, or data) to show that the assumptions used in determining TTC, ATC, and AFC were consistent with those used in operations or planning studies for the time period studied. (~~R8~~R6)

**~~M8~~M7.** The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has ~~updated~~ calculated the hourly, daily, and monthly ATC on at least the minimum frequencies specified in ~~R9~~R7 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R7)

**~~M9~~M8.** The Transmission Service Provider shall provide a copy of the dated request for ATC data as well as evidence to show ~~the its~~it ~~response~~ responded to that request (such as logs or data~~,~~) ~~to show that~~ within ~~fourteen~~ thirty calendar days of receiving ~~a~~ the request, and the requested data items ~~specified in R10~~ were made available in accordance with R~~10~~8. (R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

### 1.3. Data Retention

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, ~~R4, R5 and R8~~ R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- ~~The Transmission Service Provider shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.~~
- The Transmission Service Provider shall maintain evidence to show compliance with ~~R7~~ R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with ~~R8~~ R6 for the most recent calendar year plus the current year.
- ~~The Transmission Service Provider shall maintain evidence to show compliance with R9 and R10 for the most recent calendar year plus the current year.~~
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Operator did not select one or more of the specified methodologies. |
| R2. | N/A | N/A | N/A | The ~~Transmission Operator or~~ Transmission Service Provider did not calculate ATCs based on the time periods in R2.<br>**OR**<br>D~~d~~id not use the selected methodology(ies) to calculate ATC. |
| R3.<br>~~R4.~~<br>~~R5.~~ | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago.<br>~~N/A~~<br>~~N/A~~ | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago.<br>~~N/A~~<br>~~N/A~~ | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>**OR**<br>The Transmission Service Provider has an ATCID, but it does not include two or more of the information items described in R3.<br>~~N/A~~<br>~~N/A~~ | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>**OR**<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include any of the information described in R3.<br>~~The Transmission Service provider did not use counterflows in the determination of ATC as described in R4 or its ATCID.~~<br>~~The Transmission Service provider did not use counterflows in the determination of ATC as~~ |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | ~~described in R5 or its ATCID.~~ |
| ~~R6~~R4. | The Transmission Service Provider ~~did not notifyed~~notified one or more of the parties specified in ~~R6~~ R4 of a new or modified ATCID ~~within~~ more than 14, but not more than 30, calendar days ~~days~~ after~~of~~ its ~~effectiveness~~implementation. | The Transmission Service Provider ~~did not~~ notif~~y~~ied one or more of the parties specified in R~~6~~4 of a new or modified ATCID ~~within~~ more than 30, but not more than 60, calendar days after ~~of~~ its ~~effectiveness~~implementation. | The Transmission Service Provider ~~did not~~ notifi~~ed~~y one or more of the parties specified in R4~~6~~ of a new or modified ATCID ~~within 60~~ more than 60, but not more than 90, calendar days ~~of~~ after its ~~effectiveness~~implementation. | The Transmission Service Provider did not notify one or more of the parties specified in R~~6~~4 of a new or modified ATCID ~~within 90~~for more than 90 calendar days ~~of~~ after its ~~effectiveness~~implementation. |
| ~~R7~~R5. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in ~~R7~~R5 |
| ~~R8~~R6. | N/A | N/A | N/A | The Transmission Service Provider or Transmission Operator did not determine ATC using assumptions consistent with those used in planning ~~and~~ or operations studies for the studied time period. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R9~~R7. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculat~~ed~~e ~~within~~ for more than 12 hours but not more than 15 hours,<br>**OR**<br>F~~f~~or Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate~~ed~~ ~~in~~for more than ~~2 days~~2 calendar days but not more than 3 calendar days,<br>**OR**<br>F~~f~~or Monthly, the values described in the ATC equation changed and the Transmission Service provider did ~~-~~not ~~calculat~~calculate for~~ed in~~ 8 or more calendar days, but less than 14 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours,<br>~~For Hourly, not calculated in more than 5 hours but not more than 10 hours,~~<br>**OR**<br>F~~f~~or Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days,<br>~~for Daily not calculated in 3 days,~~<br>**OR**<br>~~f~~For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. ~~for Monthly- not calculated in 14 or more days, but less than 21 days~~ | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours,<br>~~For Hourly, not calculated in10 hours or more, but not more than 15 hours,~~<br>**OR**<br>F~~f~~or Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days,<br>~~for Daily not calculated in 4 days,~~<br>**OR**<br>~~f~~For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. ~~for Monthly- not calculated in 21 or more days, but less than 28 days~~ | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours,<br>~~For Hourly, not calculated in15 hours or more,~~<br>**OR**<br>F~~f~~or Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days,<br>~~for Daily not calculated in 5 days or more,~~<br>**OR**<br>F~~f~~or Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days. ~~for Monthly- not calculated in 28 or more days.~~ |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R10~~R8 | N/A | The Transmission Service Provider ~~took~~ made the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available more than ~~more than 14~~30 calendar days but ~~less~~ less than ~~than 28~~ 45 calendar days ~~from~~ after receiving a request~~, to make available the requested data items specified in R10 to the entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R10~~. | The Transmission Service Provider made the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available 45 calendar days or more but less than 60 calendar days after receiving a request~~, ~~.~~The Transmission Service Provider took 28 or more calendar days, but less than 60 calendar days from receiving a request, to make available the requested data items specified in R10 to the entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R10.~~ | The Transmission Service Provider did not make the requested data items specified in R8 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R8, available for 60 calendar days or more after receiving a request~~, ~~.~~The Transmission Service Provider took 60 calendar days or more from receiving a request, to make available the requested data items specified in R10 to the entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R10.~~ |

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Implementation Plan for Standard MOD-001-1; ATC/TTC/AFC and CBM/TRM Revisions (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-001-1, which requires the selection of an ATC methodology and describes the parts of the ATC process that apply to all entities, regardless of methodology chosen.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes the current MOD-001-1.

This standard incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-001-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

**Summary Consideration of Comments:**

The Drafting Team has reviewed the comments and made some changes to the standard to address these comments.

1. As requested by BPA and others, the standard was modified to be clear that MOD-001 does not require conversion of AFC to ATC. While the OASIS Requirements require that ATC be posted, the Drafting Team could not find any reason that AFC must be converted to ATC for reliability. MOD-030 continues to provide the equation to convert AFC to ATC, that shall be used 'when' the conversion occurs, but the NERC standards do not define 'when' that conversion must occur. The standard now uses the phrase "ATC or AFC", where applicable. While the use of 'or' is not typically used in standards, since any Transmission Service Provider is only required to calculated either AFC or ATC, based on method that was selected, the use of 'or' is appropriate.
2. The title and purpose were modified to more clearly reflect the reliability aspects of 'why' ATC and AFC are calculated
3. All VRFs were set to "Lower" in response to industry comments. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
4. R2 has changed such that only 48 Hourly values are required instead of 168 Hourly values. It is necessary for reliability to know the hourly information for the next 1-2 days. However, while OASIS posting is required for 168 hours, the Drafting Team does not see any reliability benefit to calculating more than 48 hours of Hourly data. Daily values provide the necessary reliability information for time periods more than 48 hours in the future.
5. In R6 (and R7) we clarified that assumptions need to be 'no more limiting' rather than 'consistent'. In addition, the existing R6 was split to clarify which aspects the Transmission Operator and Transmission Service Provider are responsible for. Measures were expanded to be more clear.
6. A more graded approach was applied to the VSLs where appropriate
7. The Transmission Service Provider was given an 80-hour-per-year grace period in R8 for scheduled or unscheduled outages of any ATC calculation software that impact the hourly calculation.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/standards/newstandardsprocess.html.

| Entity | Comment |
|---|---|
| Alabama Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| American Electric Power | 1. This standard places obligations on the registered "Transmission Operator" however, in many cases around the continent, there are 'registered' TOPs that do not calculate ATC both by tariff (ERCOT for example) or SPP where ATC is calculated, but not by the TOPs, but by the RTO. This standard must have an exemption for TOPs that do not calculate ATC. Delegation to the party that does calculate it is not an appropriate solution, because the TO does not have the responsibility to calculate, therefore it cannot delegate.<br>Response: The Transmission Operator is responsible for handling the issues on the real-time system. Therefore, the Drafting Team believes the Transmission Operator is the appropriate entity to select the methodology, rather than be forced to implement the method selected by the Transmission Service Provider. For similar reasons, the Drafting Team believes that the Transmission Operator does have an obligation to calculate TTC or TFC. The Transmission Operator has the ability to delegate these responsibilities to the Transmission Service Provider if desired.<br><br>2. As this standard is written, the Transmission Operat or has only 2 responsibilities -- R1 to pick a calculation method for the TSP to use to calculate ATC, and R6 where the TOP must calculate consistent with planning studies. If the TOP doesn't calculate ATC, why this obligation? Even so, how would 'compliance' be measured.<br>Response: The Transmission Operator is responsible for handling the issues on the real-time system. Therefore, the Drafting Team believes the Transmission Operator is the appropriate entity to select the methodology, rather than be forced to implement the method selected by the Transmission Service Provider. For similar reasons, the Drafting Team believes that the Transmission Operator does have an obligation to calculate TTC or TFC, which is incorporated in the individual methodology standards. We have modified the standard to make this more clear. The Transmission Operator has the ability to delegate these responsibilities to the Transmission Service Provider if desired.<br><br>3. All ATC calculation issues should be on the TSP, there should be no obligation on this subject placed on the TOP.<br>Response: The Drafting Team has modified R6 and the associated measure and VSL to be clear that the responsibility of the Transmission Operator is to determine TTC or TFC, not to calculated ATC.<br>4. When this is accepted, MOD-013 is retired because those requirements are within this MOD-001 standard. TTC (FAC-012) is a reliability number and should not fall under ATC related standards.<br>Response: These ATC standards are also reliability standards, therefore, the inclusion of the TTC requirements is appropriate within these standards. |
| AEP Marketing | 1. This standard places obligations on the registered "Transmission Operator" however, in many cases around the continent, there are 'registered' TOPs that do not calculate ATC both by tariff (ERCOT for example) or SPP where ATC is calculated, but not by the TOPs, but by the RTO. This standard must have an exemption for TOPs that do not calculate ATC. Delegation to the party that does calculate it is not an appropriate solution, because the TO does not have the |

| Entity | Comment |
|---|---|
| | responsibility to calculate, therefore it cannot delegate.<br>2. As this standard is written, the Transmission Operator has only 2 responsibilities -- R1 to pick a calculation method for the TSP to use to calculate ATC, and R6 where the TOP must calculate consistent with planning studies. If the TOP doesn't calculate ATC, why this obligation? Even so, how would 'compliance' be measured.<br>3. All ATC calculation issues should be on the TSP, there should be no obligation on this subject placed on the TOP.<br>4. When this is accepted, MOD-013 is retired because those requirements are within this MOD-001 standard. TTC (FAC-012) is a reliability number and should not fall under ATC related standards. |
| AEP Service Corp. | 1. This standard places obligations on the registered "Transmission Operator" however, in many cases around the continent, there are 'registered' TOPs that do not calculate ATC both by tariff (ERCOT for example) or SPP where ATC is calculated, but not by the TOPs, but by the RTO. This standard must have an exemption for TOPs that do not calculate ATC. Delegation to the party that does calculate it is not an appropriate solution, because the TO does not have the responsibility to calculate, therefore it cannot delegate.<br>2. As this standard is written, the Transmission Operator has only 2 responsibilities -- R1 to pick a calculation method for the TSP to use to calculate ATC, and R6 where the TOP must calculate consistent with planning studies. If the TOP doesn't calculate ATC, why this obligation? Even so, how would 'compliance' be measured.<br>3. All ATC calculation issues should be on the TSP, there should be no obligation on this subject placed on the TOP.<br>4. When this is accepted, MOD-013 is retired because those requirements are within this MOD-001 standard. TTC (FAC-012) is a reliability number and should not fall under ATC related standards. |
| Response: Please see in-line responses. Note that similar comments have been grouped and responded to once. | |
| Associated Electric Cooperative, Inc. | The VSLs are very high for something that may be minor. If an entity is typically calculating AFC or ATC every hour, however due to some software or maintenance issue misses one on the hours why would the severity level be so high? I think it is inappropriate to have the VSL be high. It should be minor in this case. |
| Response: The Drafting Team has reviewed the quantity of ATCs that were required in R2 and has changed the requirement from 168 Hourly values to 48 Hourly values. It is necessary for reliability to know the hourly information for the next 1-2 days. However, while OASIS posting is required for 168 hours, the Drafting Team does not see any reliability benefit to calculating more than 48 hours of Hourly data. Daily values provide the necessary reliability information for time periods more than 48 hours in the future.<br>The VSLs have been modified to include a graduated approach. | |
| Barry Green Consulting Inc. | Transparency: The former NERC standard for ATC required only that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose.<br>We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td></td><td>shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency.<br><br>The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to it. Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID is reminiscent of the former ATC standard and cannot assure market participants of a sufficient degree of standardization.</td></tr>
<tr><td colspan="2">Response: The standard in R4 and R5 specifies the reliability entities to which the ATCID will be supplied, and NAESB is responsible for determining which information will be shared with market participants. While the standard does promote enhanced transparency, the purpose has been reworded to focus more on the reliability aspects of the standard. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation.</td></tr>
<tr><td>Bonneville Power Administration</td><td>The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make the necessary modifications to MOD-001-1 to reflect the removal of the conversion requirement. BPA would vote "Yes", if the following modifications were made to MOD-001-1:<br>– Change the following Requirements, Measures, and Violation Severity Levels to replace each "ATC" with "ATC or AFC": first use in R2, R2.1-R2.3, R3.1, R3.2.1, R3.3, R3.7-R3.7.2, R7-R.8, M2 (including the three dashes), M7, M8, R2 Severe VSL, R6 Severe VSL, and R7 Lower VSL - Severe VSL.<br>– Change the following Requirements and Measures to include the missing "TFC" term: R6 and M6.<br>– Change the Data Retention requirement in the first dash of 1.3 to replace "ATC" with "ATC or AFC".</td></tr>
<tr><td>Bonneville Power Administration</td><td>The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make the necessary modifications to MOD-001-1 to reflect the removal of the conversion requirement. BPA would vote "Yes", if the following modifications were made to MOD-001-1:<br>– Change the following Requirements, Measures, and Violation Severity Levels to replace each "ATC" with "ATC or AFC": first use in R2, R2.1-R2.3, R3.1, R3.2.1, R3.3, R3.7-R3.7.2, R7-R.8, M2 (including the three dashes), M7, M8, R2 Severe VSL, R6 Severe VSL, and R7 Lower VSL - Severe VSL.<br>– Change the following Requirements and Measures to include the missing "TFC" term: R6 and M6.<br>– Change the Data Retention requirement in the first dash of 1.3 to replace "ATC" with "ATC or AFC".</td></tr>
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</table>

| Entity | Comment |
|---|---|
| | – Change the following Requirements and Measures to include the missing "TFC" term: R6 and M6.<br>– Change the Data Retention requirement in the first dash of 1.3 to replace "ATC" with "ATC or AFC". |
| Bonneville Power Administration | The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make the necessary modifications to MOD-001-1 to reflect the removal of the conversion requirement. BPA would vote "Yes", if the following modifications were made to MOD-001-1:<br>– Change the following Requirements, Measures, and Violation Severity Levels to replace each "ATC" with "ATC or AFC": first use in R2, R2.1-R2.3, R3.1, R3.2.1, R3.3, R3.7-R3.7.2, R7-R.8, M2 (including the three dashes), M7, M8, R2 Severe VSL, R6 Severe VSL, and R7 Lower VSL - Severe VSL.<br>– Change the following Requirements and Measures to include the missing "TFC" term: R6 and M6.<br>– Change the Data Retention requirement in the first dash of 1.3 to replace "ATC" with "ATC or AFC".<br>Excerpt from the Summary Consideration of question six of the Comment Report Form for 3rd Draft of MOD-001; 2nd Draft of MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 - Project 2006-07: "[MOD-030-1] was modified to state that entities were required to use the provided formula to calculate ATCs and TTCs if they were doing such a conversion, but that the standards did not actually require the conversion." In Order 890 P 211, Order 890-A P 41 and 51, and Order 639 P 1031, FERC clearly indicated that the requirement to convert AFC to ATC is an OASIS posting requirement. In order to ensure that transmission providers were consistent in how AFC was converted to ATC, FERC directed NERC to develop a standard conversion formula. The use of "ATC" and the omission of "AFC" in MOD-001 could be interpreted to require conversion. |
| Response: The Drafting Team modified the standard to ensure that MOD-001 does not require the conversion from AFC to ATC, as it does not seem to serve a reliability purpose. Note that similar comments have been grouped and responded to once. | |
| Calpine Corporation | The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose.<br>We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency.<br>The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to the document. Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization. |
| Response: The standard in R4 and R5 specifies the reliability entities to which the ATCID will be supplied, and NAESB is responsible for determining which information will be shared with market participants. While the standard does promote enhanced transparency, the purpose has been reworded to focus more on the reliability aspects of the standard. The Drafting Team believes that the standard provides an | |

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| appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation. | |
| CenterPoint Energy | ERCOT's filed comments to the SDT that ATC, TTC, CBM, and TRM are not applicable within ERCOT operations and that these Standards should have provisions that make it clear that these requirements apply only within market structures in which they are pertinent were ignored by the SDT. These standards should not apply to ERCOT, thus our negative vote. |
| Response: | MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any path for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. |
| City of Tallahassee | Calculating/reporting requirements are too burdensome for smaller systems with little or no real TTC (or ATC) for posting. This standard will require substantial commitment of resources to implement with little benefit to the TP or the surrounding grid. |
| Response: | The Drafting Team has reviewed the quantity of ATCs that were required in R2 and has changed the requirement from 168 Hourly values to 48 Hourly values. It is necessary for reliability to know the hourly information for the next 1-2 days. However, while OASIS posting is required for 168 hours, the Drafting Team does not see any reliability benefit to calculating more than 48 hours of Hourly data. Daily values provide the necessary reliability information for time periods more than 48 hours in the future. |
| Dominion Resources, Inc. | In support of PJM comments |
| Response: Please see response to PJM. | |
| Dominion Resources, Inc. | Support comments provided by PJM |
| Response: Please see response to PJM. | |
| Electric Power Supply Association | The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose.<br>We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency.<br>The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if |

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| | it is not yet determined which parties will have access to the document. Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization. |
| Response: The standard in R4 and R5 specifies the reliability entities to which the ATCID will be supplied, and NAESB is responsible for determining which information will be shared with market participants. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation. | |
| Florida Municipal Power Agency | We believe this standard needs an additional commenting period. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
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| Florida Municipal Power Agency | We believe this standard needs an additional commenting period. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| FirstEnergy Energy Delivery | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br>CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc.<br>Response: Please see responses contained in the CBM and TRM comment reports.<br><br>FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both. Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was |

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| | near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br>Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.<br><br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>– We do not agree with the Transmission Operator (TOP) having the ultimate responsibility in selection of the ATC methodology. This should be the responsibility of either the Planning Coordinator (PC) or Transmission Service Provider (TSP). This is especially true when a TSP is providing service that crosses multiple TOP systems such as market areas. In these situations, it is not practical for a TOP to be selecting an ATC methodology. Additionally, per Requirement R1 the standard allows for the selection of different ATC methodologies for each ATC Path for various time periods.<br>Response: Since these standards only deal with the 13 month timeframe, the Drafting Team does not agree that the Planning Coordinator is appropriate. In addition, the Transmission Operator is responsible for handling the issues on the real-time system. Therefore, the Drafting Team believes the Transmission Operator is the appropriate entity to select the methodology, rather than be forced to implement the method selected by the Transmission Service Provider. The Transmission Operator has the ability to delegate the responsibility to the Transmission Service Provider if desired.<br><br>– Although we agree with allowing for three different methodologies to match the way different areas of the bulk electric system perform ATC calculations, throughout a single area one specific ATC methodology should be used for all of the paths and time periods. This would result in more consistent ATC calculations. At minimum, it is expected that all participants within a market area would conform to a single ATC methodology.<br>Response: The Drafting Team disagrees. The Drafting Team has seen specific examples where there are valid reasons to use different methods internally versus on external interfaces. Seams management may result in needs for different methodologies on external interfaces than those used for internal paths. In addition, there are valid reasons for using different methods for different timeframes. For example, timeframes that are farther out allow for a more computationally intensive method than can be used in a shorter timeframe.<br><br>– The standard should be clear on how often and what periodicity the ATC methodology is chosen. It would be a reasonable expectation for an entity to use a given methodology for a minimum period of time before a different methodology can be chosen. FE suggests that the methodology be chosen on an annual basis, or even less often if the team feels that would be appropriate.<br>Response: The Drafting Team does not believe it is appropriate for the standards to define how long a selected method |

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| | must be utilized. The ATCID must be updated and distributed before any change in method is applied. Also, there are business processes and software requirements involved such that it is not likely that entities will alternate between methodologies.<br><br>– With regard to Requirement R6, this requirement requires the TSP and TOP to provide consistent ATC calculations based on assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. This requirement is aimed at the calculation (end result), which is the responsibility of the TSP and FE believes it is appropriate to remove the TOP from this requirement.<br>Response: R6 (and its corresponding Measure and VSL) was separated into two requirements to address the specific aspects applicable to the Transmission Service Provider and the Transmission Operator.<br><br>– The TOP's requirement for providing support via modeling data for use by the TSP is already addressed in the applicable methodology standard (for example, refer to R3 of MOD-030).<br>Response: The Drafting Team agrees that MOD-028, MOD-029, and MOD-030 include details with the Transmission Operator responsibilities, but this requirement is addressing the consistency of assumptions and is common to all three MODs, so it is located in MOD-001. |
| FirstEnergy Solutions | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br>CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc. FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both.<br>Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve |

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| | consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>– We do not agree with the Transmission Operator (TOP) having the ultimate responsibility in selection of the ATC methodology. This should be the responsibility of either the Planning Coordinator (PC) or Transmission Service Provider (TSP). This is especially true when a TSP is providing service that crosses multiple TOP systems such as market areas. In these situations, it is not practical for a TOP to be selecting an ATC methodology.<br>– Additionally, per Requirement R1 the standard allows for the selection of different ATC methodologies for each ATC Path for various time periods. Although we agree with allowing for three different methodologies to match the way different areas of the bulk electric system perform ATC calculations, throughout a single area one specific ATC methodology should be used for all of the paths and time periods. This would result in more consistent ATC calculations. At minimum, it is expected that all participants within a market area would conform to a single ATC methodology.<br>– The standard should be clear on how often and what periodicity the ATC methodology is chosen. It would be a reasonable expectation for an entity to use a given methodology for a minimum period of time before a different methodology can be chosen. FE suggests that the methodology be chosen on an annual basis, or even less often if the team feels that would be appropriate.<br>– With regard to Requirement R6, this requirement requires the TSP and TOP to provide consistent ATC calculations based on assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. This requirement is aimed at the calculation (end result), which is the responsibility of the TSP and FE believes it is appropriate to remove the TOP from this requirement.<br>– The TOP's requirement for providing support via modeling data for use by the TSP is already addressed in the applicable methodology standard (for example, refer to R3 of MOD-030). |
| FirstEnergy Solutions | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below.<br>CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc. FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both.<br>Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.<br>DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should |

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| | have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.<br><br>FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>– We do not agree with the Transmission Operator (TOP) having the ultimate responsibility in selection of the ATC methodology. This should be the responsibility of either the Planning Coordinator (PC) or Transmission Service Provider (TSP). This is especially true when a TSP is providing service that crosses multiple TOP systems such as market areas. In these situations, it is not practical for a TOP to be selecting an ATC methodology.<br>– Additionally, per Requirement R1 the standard allows for the selection of different ATC methodologies for each ATC Path for various time periods. Although we agree with allowing for three different methodologies to match the way different areas of the bulk electric system perform ATC calculations, throughout a single area one specific ATC methodology should be used for all of the paths and time periods. This would result in more consistent ATC calculations. At minimum, it is expected that all participants within a market area would conform to a single ATC methodology.<br>– The standard should be clear on how often and what periodicity the ATC methodology is chosen. It would be a reasonable expectation for an entity to use a given methodology for a minimum period of time before a different methodology can be chosen. FE suggests that the methodology be chosen on an annual basis, or even less often if the team feels that would be appropriate.<br>– With regard to Requirement R6, this requirement requires the TSP and TOP to provide consistent ATC calculations based on assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. This requirement is aimed at the calculation (end result), which is the responsibility of the TSP and FE believes it is appropriate to remove the TOP from this requirement.<br>– The TOP's requirement for providing support via modeling data for use by the TSP is already addressed in the applicable methodology standard (for example, refer to R3 of MOD-030). |
| FirstEnergy Solutions | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:<br>– We do not agree with the Transmission Operator (TOP) having the ultimate responsibility in selection of the ATC methodology. This should be the responsibility of either the Planning Coordinator (PC) or Transmission Service Provider (TSP). This is especially true when a TSP is providing service that crosses multiple TOP systems such as |

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| Response: Please see in-line responses. Note that similar comments have been grouped and responded to once. | |
| Great River Energy | GRE supports BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period based on the significance of the comments submitted during the previous commenting periods. |
| Response: The Drafting Team will be sending the standards out for another round of comments prior to continuing the balloting process | |
| Georgia Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Gulf Power Company | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Hydro One Networks, Inc. | Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighboring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those |

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| | where such regulatory approval in not required that is, only when all regulatory approvals have been obtained, |
| Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by all applicable regulatory authorities. | |
| Hydro One Networks, Inc. | Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighboring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained. |
| Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. | |
| Independent Electricity System Operator | While we are in general support of this substantially improved standard and the efforts of the standards drafting team (SDT) and have voted YES to MOD-001. We nonetheless, believe that the fundamental purpose of these MOD standards, which is to promote a "consistent" and "reliable" application of Available Transfer Capability (ATC) calculations between BA Areas, is being compromised due to the proposed effective dates. In principle, we believe the effective date of all standards must be the same for all jurisdictions in North America. This is particularly important in the MOD Standards in ballot as they have implications on neighboring areas with varying implementation dates. |
| Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. | |
| Lincoln Electric System | LES supports BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Lincoln Electric System | LES supports BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Lincoln Electric System | LES supports BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |

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| Madison Gas and Electric Co. | We support BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| MidAmerican Energy Co. | I support the BPA position for changes to take AFC to ATC and TFC to TTC conversions out of this standard. I also support the PJM recommendation that this standard needs an additional commenting period. |
| Response: Please see BPA and PJM responses. | |
| MidAmerican Energy Co. | Although this standard leaves much to be desired, it is better than the current standard. I hope NERC continues to work towards consistency in the arena of transfer capability. |
| Response: Thank you for your comments; the Drafting Team will consider them in subsequent revisions to the standards. | |
| Midwest Reliability Organization | The MRO supports BPA position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| Mississippi Power | We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| New York Independent System Operator | As an initial matter, the NYISO supports, and incorporates by reference, the five "general" objections to proposed standards MOD-001, MOD-004, MOD-008, and MOD-030, that were raised by the PJM Interconnection, LLC in Sections I-V of its February 29 pre-ballot comments. The NYISO also raises these general objections in its comments on proposed MOD standards -028 and -029 notwithstanding the fact PJM intends to abstain from voting on those standards. Specifically:<br>– The proposed standards should have been sent out for comment not pre-ballot posting. Because there are still a number of significant questions about them and because there are instances where the proposed standards may not be broad enough to accommodate alternative means of compliance.<br>Response: The Drafting Team is posting the standards for an industry comment period<br><br>– The proposed standards are overly detailed. They contain requirements that should be left for "Business Practices" as that term is defined in MOD-001, creating an unnecessary likelihood of conflict with applicable tariffs, rules, procedures and/or market rules.<br>Response: The Drafting Team disagrees that the standards are too detailed and does not understand which requirements you see that would conflict with tariffs or market rules. When these standards are published for comment again, please provide specific suggestions on what you believe should be modified.<br><br>– The proposed violation risk factors are too severe. None of the ATC standards should have a risk factor beyond |

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| | "Lower" under NERC's own violation risk factor definitions, since violations should not be expected to affect the reliability of the bulk power system.<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br><br>– The proposed violation severity levels are not complete and several proposed levels should be revised to include gradations that reflect the fact that substantial compliance should not be treated as harshly as total non-compliance.<br>Response: Where possible, the VSLs have been broken into graduated levels rather than only one level.<br><br>The description of how system outages are applied and the requirement to include all of those outages has a high chance of resulting in noncompliance findings that are unreasonable. The NYISO's December 14 Comments on the third draft of the proposed MOD standards explained in detail how ATC serves a fundamentally different purpose and is calculated differently, with respect to interfaces internal to New York, under the NYISO's Commission-approved "financial reservation" transmission model. Under that system, there are no express physical transmission reservations, all desired uses of the grid are accommodated to the extent that customers are willing to pay congestion, i.e., customers' ability to schedule transactions is not limited by a pre-defined amount of ATC. Instead, ATC postings are really "advisory projections" based on schedules calculated by the NYISO's day-ahead and real-time market software. The Commission has granted the NYISO a number of waivers from its OASIS regulations that reflect these differences. The December 14 Comments further explained that the NYISO believed that its form of financial reservation service would fit within the framework of NERC's proposed definitions and standards provided that NERC interpreted them with reasonable flexibility. The NYISO does not believe that there is anything in the latest version of the proposed MOD standards that is inconsistent with this interpretation.<br>The NYISO notes, however, that the latest version of MOD-001 replaces the definition of "Posted Path" with a new term "ATC Path" that is then used throughout the proposed MOD standards. The definition of "ATC Path," i.e., "[a]ny combination of Point of Receipt or Point of Delivery for which ATC is calculated," is broader than the definition of "Posted Path," which is comparable to the definition used in FERC's OASIS regulations. The broader definition has the potential to come into conflict with waivers the NYISO has previously been granted by FERC that exempt it from the requirement to post ATC values beyond the day-ahead period for its internal interfaces. |

| Entity | Comment |
|---|---|
| | This potential for conflict was much less significant when the MOD standards were focused on "Posted Paths" because the NYISO's internal interfaces normally would not be counted as Posted Paths. The NYISO respectfully requests that the SDT either return to its use of the term "Posted Path" or that NERC clarify that it will not seek to enforce MOD requirements against entities that have waivers from FERC that conflict with them.<br>Response: The Drafting Team changed the definition from Posted Path to ATC Path because the definition of Posted Path did not completely capture where ATC should be calculated for reliability, and will not be reverting back to the use of Posted Path.  The Drafting Team does not understand how the change in use of "ATC Path" versus "Posted Path" will impact the NYISO.  If you are calculating ATC for internal paths, it is not clear how this standard will conflict with your current practice.<br><br>The NYISO has a similar concern with respect to M2 under MOD-001 which assumes that all Transmission Service Providers are required to post ATC beyond the day-ahead period on all of their interfaces.<br>Response: This standard is only discussing the calculation of ATC, not the posting of ATC.<br><br>The NYISO respectfully asks that NERC clarify that it will not seek to enforce this rule against entities that have FERC waivers of the relevant underlying OASIS regulation.<br>Response: These standards are written for reliability purposes and are not related to OASIS regulations.  It is outside the Drafting Team's scope of responsibility to make interpretations on how these standards will be enforced.<br><br>The December 14 Comments asked the SDT to revise requirements R10.3 through R10.8, and R10.14, which have now been renumbered under R8, or in the alternative, clarify that they do not apply to transmission providers, such as the NYISO, that use financial reservation models and thus will not have the information that the proposed requirements direct them to make available on request. Otherwise, these information requirements would effectively call on the NYISO to perform functions that FERC's waiver orders excuse it from performing and that would serve no purpose under the NYISO model. The SDT has not made the requested clarifications or revisions. The NYISO therefore respectfully renews its request that the SDT do so.<br>Response:  R9.1 states "Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider". The Drafting Team believes this addresses the NYISO concern without additional changes being required.<br><br>Consistent with Sections I above and with PJM's specific comments on this issue, none of the violation risk factors in MOD-001 should have a rating beyond "Lower," the proposed violation severity levels should be reviewed so that they include appropriate gradations, and the requirements that PJM has identified as being overly detailed should be eliminated and the underlying issues left for NAESB or to the individual practices of Transmission Service Providers and other entities.<br>Response: Please see responses above and responses to PJM. |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Orlando Utilities Commission</td><td>This standard should contain only 'lower' level VRFs.</td></tr>
<tr><td colspan="2">Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for “a requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures.” A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator’s existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.</td></tr>
<tr><td>PJM Interconnection, L.L.C.</td><td>– PJM believes no requirement from the set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.<br><br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for “a requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures.” A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator’s existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br><br>– The ATC MOD standards should have been sent out for comment not pre-ballot posting.<br><br>Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.<br><br>– PJM believes that the MOD standards go too far in areas that should be covered and addressed by Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices not in NERC standards as reliability based requirements (see specific details for MOD-001 R2 and R7 and MOD-030 R10 in Specific Comments sections below). Not recognizing the clear</td></tr>
</table>

| Entity | Comment |
| --- | --- |
| | distinction between the reliability scope to be addressed by these standards and the NAESB business practices could cause inconsistencies in interpretation.<br>Response: The Drafting Team believes that ATC calculations are reliability related. While the Drafting Team does agree that the sale of transmission service and that the underutilization of the transmission system is not a reliability issue, the over-scheduling of the transmission system can have significant reliability implications. An overscheduled condition can require operator intervention; ATC or AFC calculations can provide indicators of the effect planned transfers will have on the transmission system and allows the associated reliability entities to plan accordingly. As such, the standards must provide clear requirements on how many and how often the calculations must occur to be measurable. The number of required hourly values was reduced from 168 from 48 to reflect the reliability need for the ATC calculations.<br><br>The Drafting Team agrees that the frequency of posting should be a NAESB business practice.<br><br>– NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards need to be developed with a more graded implementation for several requirements. The VSLs for several requirements do not consistently include the graded degree of achieving compliance. To the extent that reliability and transparency can be maintained in the event that the entity does not meet the measures the VSL is often excessive. Some VSLs do not recognize the potential varying level of non-compliance with the requirement. With these requirements there are several instances where the VSLs should have incorporated the following distinctions:<br>a. Recognizing gross violation of the requirement - for example the entity's program ignores the requirement.<br>b. Recognizing programmatic issues exist with the implementation of the requirement leading failure to meet some of the requirement. For example if only 167 hours of hourly ATC values instead of 168 hours are calculated it would be a violation with a severe sanction indicating that reliability was severely affected. The actual impact being minimal since customers can only reserve hourly ATC for 24 to 48 hours in the future out of the 168 hours. It is clear that the SDT recognized differences in severity levels in some of the requirements such as MOD001 requirement 7. This was accomplished by specifying timeframes and numbers of instances of not meeting the requirements. However the VSLs in several instances throughout the standard(s) do not reflect this approach.<br>The SDT should continue with a more graded implementation of VSLs for:<br>– MOD001-1:<br>o R2, R5, and R6 Requirement 1 The violation risk factor should be "Lower."<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for “a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures.” A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other |

| Entity | Comment |
| --- | --- |
| | processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br>o Requirement 2 1.<br>▪ The requirements listed in R2 are business practices and should be considered NAESB scope and eliminated.<br>Response: ATC is reliability related and as such, requirements must be defined on the timing of the ATC calculations that are measurable. The quantity of hours required for hourly has been modified to reflect the data required for reliability<br>▪ 2. The medium risk factor is inconsistent with NERC's definition of risk factors and should be changed to lower if the requirement is to be retained.<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.<br>▪ 3. The Violation Severity Level should be more thorough. If only 167 hours of hourly ATC values instead of 168 hours are calculated it would be a violation with a severe sanction indicating that reliability was severely affected. Customers can only reserve hourly ATC for 24 to 48 hours in the future of the 168 hours. Since fines are a function of both risk factors and Violation Severity Levels the entity would again be fined inconsistent with the reliability impact.<br>Response: The Drafting Team has modified the VSL to have more than one level.<br>o Requirements 3 and 8<br>▪ R3.2.1 and R8 fifth bullet PJM believes reservations that are in "Accepted ", as well as, "Confirmed" status should be included. Once service is "Accepted" by a TSP it cannot be retracted. Using reservations that are in "Accepted" and "Confirmed" status should also be included in MOD-030 R6.3.<br>Response: Only Confirmed request are to be taken out in the ATC calculations under these standards, since reservations |

| Entity | Comment |
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| | in an Accepted state (that were not pre-confirmed) may be withdrawn by the customer. However, R8 has been modified to remove the term 'confirmed' so that parties may ask for data exchange of additional statuses.<br><br>▪ The description of how system outages are applied and the requirement to include all of those outages has a high chance of noncompliance. A suggestion is to add a time duration for how long an outage can be temporarily excluded due to naming or modeling issue. Another exemption would be to block non-critical outages that cause problems arriving at a loadflow solution (see MOD001-R3.7 and MOD030 R5.2).<br>Response: The ATCID is intended to allow entities to document how to handle these scenarios. R3.6 was modified to remove the term 'duration', indicating a more detailed description is required of how outages are handed.<br><br>o Requirement 6<br>▪ This requires the use of assumptions consistent with those used in associated operations studies or planning studies. PJM believes language should be added as follows: Assumptions used in studies not associated with calculating TTC, AFC, and need not be used.<br>Response: This requirement has been separated to clearly address the Transmission Service Provider versus the Transmission Operators responsibilities. In addition, the phrase 'consistent' was replaced with 'no more limiting than'.<br><br>▪ The requirement should be modified to recognize allocation processes as acknowledged in R3.6. The allocation process may affect the value of ATC. The intent of the requirement would be met but not the requirement itself as written.<br>Response: The Drafting Team has addressed this issue by modifying that the assumptions shall be 'no more limiting than' rather than 'consistent'.<br><br>o Requirement 7<br>▪ The requirement is a business practice and should be NAESB scope. This requirement also makes no distinction between firm and non-firm service and assumes the reliability risk is the same.<br>Response: ATC is reliability related and as such, these standards must include measurable requirements on how often the values must be calculated to ensure the data is not stale. The VRF is already lower, whether it applies to firm or non-firm, so there is no way to reflect that not meeting this requirement for non-firm may have a lower reliability risk that firm.<br><br>o Requirement 8<br>▪ R8 should not require the entities to supply data that is not specifically part of the ATC calculation. The requirement should state the entity is to provide information in the form that it has been used. |

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td></td><td>Response: R9.1 (previously 8.1) currently states this.<br><br>▪ R8 fifth bullet--PJM believes reservations in "Accepted", as well as, "Confirmed" status should be included.<br>Response: The status of the reservations was removed to allow the requestor to define what status reservations they want to receive</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Portland General Electric Co.</td><td>The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make the necessary modifications to MOD-001-1 to reflect the removal of the conversion requirement. BPA would vote "Yes", if the following modifications were made to MOD-001-1:<br>– Change the following Requirements, Measures, and Violation Severity Levels to replace each "ATC" with "ATC or AFC": first use in R2, R2.1-R2.3, R3.1, R3.2.1, R3.3, R3.7-R3.7.2, R7-R.8, M2 (including the three dashes), M7, M8, R2 Severe VSL, R6 Severe VSL, and R7 Lower VSL - Severe VSL.<br>– Change the following Requirements and Measures to include the missing "TFC" term: R6 and M6.<br>– Change the Data Retention requirement in the first dash of 1.3 to replace "ATC" with "ATC or AFC".</td></tr>
<tr><td colspan="2">Response: Please see response to BPA</td></tr>
<tr><td>Potomac Electric Power Co.</td><td>Potomac Electric agrees with the comments of PJM distributed to the ballot body. I will not repeat them here, but do include the headings:<br>– The ATC MOD standards should have been sent out for comment not pre-ballot posting.<br>– Depth of the ATC MOD standards is excessive.<br>– Determining Violation Risk Factors is incorrect.<br>– Determining Violation Severity Levels is incomplete.</td></tr>
<tr><td colspan="2">Response: Please see response to PJM.</td></tr>
<tr><td>Public Service Electric and Gas Co.</td><td>PSE&G votes NO for the reasons expressed in PJM's comments.</td></tr>
<tr><td colspan="2">Response: Please see response to PJM.</td></tr>
<tr><td>Public Service Electric and Gas Co.</td><td>PSE&G votes NO for the reasons expressed in PJM's comments.</td></tr>
<tr><td colspan="2">Response: Please see response to PJM.</td></tr>
<tr><td>PSEG Power LLC</td><td>PSEG Power LLC votes no for the reasons expressed in PJM's comments.</td></tr>
<tr><td colspan="2">Response: Please see response to PJM.</td></tr>
</table>

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td>PSEG Energy Resources & Trade LLC</td><td>PSEG Energy Resources & Trade LLC votes NO for the reasons expressed in PJM's ballot.</td></tr>
<tr><td colspan="2">Response: Please see response to PJM.</td></tr>
<tr><td>Sierra Pacific Power Co.</td><td>While much great work was undertaken by the SDT in preparing this Standard, I am voting Negative on this Standard primarily for two reasons:<br>– First, I disagree with the assertion in this Standard that any of the Requirements are a Reliability matter. As per our previous comments, ATC is a commercial product, a commodity that is offered by transmission service providers, sold to transmission customers, and perhaps traded among such customers. The body of NERC Standards should be restricted to those that have an impact upon the reliability of the Bulk Electric System.<br>Response: The Drafting Team has adjusted the quantity of ATC or AFC data that must be calculated to better reflect the reliability need for the data, such that only 48 hours of hourly values are required instead of 168 hours. While the Drafting Team does agree that the sale of transmission service and that the underutilization of the transmission system is not a reliability issue, the over-scheduling of the transmission system can have significant reliability implications. An overscheduled condition can require operator intervention; ATC or AFC calculations can provide indicators of the effect planned transfers will have on the transmission system and allows the associated reliability entities to plan accordingly.<br><br>– Second, and related, is that the Violation Risk Factors are incorrect on R1, R2, and R4 at "medium". As the entire Standard pertains only to non-reliability matters, there is no reason for a VRF higher than "lower".<br>Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for “a requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures.” A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator’s existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>Southern Company Services, Inc.</td><td>We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team.</td></tr>
<tr><td colspan="2">Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.</td></tr>
<tr><td>Westar Energy</td><td>R2. Should be ONLY one method for each Transmission Provider, not different method for each Transmission Owner.<br>R8. Certain information, i.e. Power flow models will not be supplied to ANY/ALL requestors; R8 should specify "Qualified"</td></tr>
</table>

| Entity | Comment |
|---|---|
| | requestors. |
| Response: The Transmission Operator is responsible for handling the issues on the real-time system. Therefore, the Drafting Team believes the Transmission Operator (not the Transmission Owner) is the appropriate entity to select the methodology, rather than be forced to implement the method selected by the Transmission Service Provider. The Transmission Operator has the ability to delegate the responsibility to the Transmission Service Provider if desired.<br>All entities that can request information in R8 (R9) are NERC registered functional entities and by definition they are all 'qualified' requestors. | |
| Wisconsin Public Service Corp. | The WPSC supports BPA position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period. |
| Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. | |
| WPS Resources Corp. | R5 – The ATCID of the Transmission Service Provider should also be publicly available. Making the ATCID only available to TOs, TPs, RC, and Planning Authorities defeats the purpose of the ATCID document - transparency in the implementation of an ATC methodology. |
| Response: NAESB is responsible for the dissemination of publicly available information. | |
| Wyoming Public Service Commission | This standard should be read as not preventing the use of ADI or similar enhancements. It should be applied to give maximum flexibility to regional and sub-regional entities in dealing with the particular and sometimes localized challenges of the Western Interconnection. |
| Response: The Drafting Team does not believe the standard prohibits the use of ACE Diversity Interchange (ADI) or similar enhancements. If Wyoming Public Service Commission believes otherwise, please detail the potential conflicts in future comments. | |

**Barbara Bogenrief**

**From:** Barbara Bogenrief
**Sent:** Monday, March 03, 2008 9:27 AM
**To:** Barbara Bogenrief
**Subject:** REVISED ANNOUNCEMENT - Ballot Windows Open for Project 2006-07

REVISED Announcement: The previous announcement was inadvertently sent with incorrect links. I apologize for any inconvenience this may have caused.

Barbara Bogenrief
Standards Process Administrator

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Standards Announcement

## Ballot Windows Open
## March 3–12, 2008

**Now available at: http://www.nerc.com/~filez/standards/MOD-V0-Revision.html**

### Six Ballot Windows for Project 2006-07 — ATC/TTC and CBM/TRM Open March 3, 2008

The initial ballot for each of the six ATC-related standards (and its associated implementation plan) is open and will remain open until 8 p.m. (EDT) on March 12, 2008. Each standard has its own ballot as shown in the following table.

This set of standards is aimed at consistent and transparent calculation, verification, and use of Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). NERC has a commitment to deliver these standards to FERC by May 9, 2008.

| Standard | Description | Ballot |
|---|---|---|
| MOD-001-1<br>Available Transfer Capability | An "umbrella" standard with requirements for the selection of a methodology, the updating of values, and the sharing of procedures and data related to ATC. | ATC-TTC-CBM-MOD-001 |
| MOD-004-1<br>Capacity Benefit Margin | A standard with requirements for requesting, calculation, and use of CBM. | ATC-TTC-CBM-MOD-004 |
| MOD-008-1<br>Transmission Reliability Margin | A standard with requirements for the calculation and use of TRM. | ATC-TTC-CBM-MOD-008 |
| MOD-028-1<br>Area Interchange Methodology | A standard with requirements for the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection. | ATC-TTC-CBM-MOD-028 |
| MOD-029-1<br>Rated System Path Methodology | A standard with requirements for the calculation of TTC and ATC, as performed primarily in the Western Interconnection. | ATC-TTC-CBM-MOD-029 |
| MOD-030-1<br>Flowgate Methodology | A standard with requirements for the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC. | ATC-TTC-CBM-MOD-030 |

### Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

*For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.*

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# Standards Ballot Reminder

## Initial Ballot Results

**Now available at: http://www.nerc.com/~filez/standards/MOD-V0-Revision.html**

**Initial Ballot Results for Six ATC-related Standards**

The initial ballot for each of the six ATC-related standards (and its associated implementation plan) was conducted from March 3–12, 2008 and the results are shown below. Approval requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non responses.

The Ballot Results standards Web page provides a link to the detailed results of each of these ballots. All of the ballots received some negative ballots with comments, and the drafting team will review the comments before determining its next step.

| Title | Initial Ballot | |
|---|---|---|
| | Quorum | Approval |
| MOD-001-1 Available Transfer Capability | 93.12 % | 59.63 % |
| MOD-004-1 Capacity Benefit Margin | 93.01 % | 38.80 % |
| MOD-008-1 Transmission Reliability Margin | 93.12 % | 63.90 % |
| MOD-028-1 Area Interchange Methodology | 92.74 % | 63.05 % |
| MOD-029-1 Rated System Path Methodology | 92.86 % | 57.56 % |
| MOD-030-1 Flowgate Methodology | 93.01 % | 44.19 % |

**Standards Development Procedure**

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.*

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Administration



| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC-TTC-CBM-MOD-001_in |
| **Ballot Period:** | 3/3/2008 - 3/12/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 176 |
| **Total Ballot Pool:** | 189 |
| **Quorum:** | **93.12 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 59.63 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 58 | 1 | 32 | 0.64 | 18 | 0.36 | 4 | 4 |
| 2 - Segment 2. | 10 | 0.9 | 5 | 0.5 | 4 | 0.4 | 0 | 1 |
| 3 - Segment 3. | 44 | 1 | 22 | 0.595 | 15 | 0.405 | 5 | 2 |
| 4 - Segment 4. | 7 | 0.5 | 2 | 0.2 | 3 | 0.3 | 2 | 0 |
| 5 - Segment 5. | 30 | 1 | 12 | 0.5 | 12 | 0.5 | 4 | 2 |
| 6 - Segment 6. | 25 | 1 | 10 | 0.5 | 10 | 0.5 | 3 | 2 |
| 7 - Segment 7. | 1 | 0.1 | 1 | 0.1 | 0 | 0 | 0 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 6 | 0.5 | 5 | 0.5 | 0 | 0 | 1 | 0 |
| 10 - Segment 10. | 6 | 0.5 | 4 | 0.4 | 1 | 0.1 | 0 | 1 |
| **Totals** | **189** | **6.6** | **93** | **3.935** | **64** | **2.665** | **19** | **13** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | Negative | View |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Negative | View |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Affirmative | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Affirmative | |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Manitoba Hydro | Michelle Rheault | Affirmative | |
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Affirmative | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | |

| | | | | |
|---|---|---|---|---|
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Negative | View |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Abstain | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Negative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Negative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Negative | View |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Negative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Negative | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Negative | View |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Negative | View |
| 3 | City of Tallahassee | Rusty S. Foster | Abstain | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Negative | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Negative | View |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Affirmative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Negative | View |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Abstain | |
| 3 | Wisconsin Public Service Corp. | James A. Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Affirmative | |
| 4 | Consumers Energy Co. | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Negative | View |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Negative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Abstain | |
| 4 | WPS Resources Corp. | Christopher Plante | Negative | View |
| 5 | AEP Service Corp. | Brock Ondayko | Negative | View |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Negative | View |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Negative | View |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Affirmative | |
| 5 | New York Power Authority | Richard J. Ardolino | Affirmative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew E. Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Abstain | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Negative | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Abstain | |
| 6 | AEP Marketing | Edward P. Cox | Negative | View |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Negative | View |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Negative | View |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Affirmative | |
| 6 | MidAmerican Energy Co. | Dennis Kimm | Affirmative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Abstain | |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Affirmative | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Utah Public Service Commission | Ric Campbell | Affirmative | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | View |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Administration



| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC-TTC-CBM-MOD-004_in |
| **Ballot Period:** | 3/3/2008 - 3/12/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 173 |
| **Total Ballot Pool:** | 186 |
| **Quorum:** | **93.01 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 38.80 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative | | Negative | | Abstain | No Vote |
|---|---|---|---|---|---|---|---|---|
| | | | # Votes | Fraction | # Votes | Fraction | # Votes | |
| 1 - Segment 1. | 57 | 1 | 19 | 0.463 | 22 | 0.537 | 12 | 4 |
| 2 - Segment 2. | 10 | 0.8 | 3 | 0.3 | 5 | 0.5 | 1 | 1 |
| 3 - Segment 3. | 43 | 1 | 14 | 0.4 | 21 | 0.6 | 6 | 2 |
| 4 - Segment 4. | 8 | 0.6 | 2 | 0.2 | 4 | 0.4 | 2 | 0 |
| 5 - Segment 5. | 29 | 1 | 8 | 0.381 | 13 | 0.619 | 6 | 2 |
| 6 - Segment 6. | 24 | 1 | 5 | 0.278 | 13 | 0.722 | 4 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 6 | 0.5 | 3 | 0.3 | 2 | 0.2 | 1 | 0 |
| 10 - Segment 10. | 6 | 0.5 | 2 | 0.2 | 3 | 0.3 | 0 | 1 |
| **Totals** | **186** | **6.5** | **56** | **2.522** | **84** | **3.978** | **33** | **13** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | Affirmative | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | View |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Negative | View |
| 1 | Duke Energy Carolina | Douglas E. Hils | Abstain | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Abstain | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Negative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Negative | View |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | View |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Negative | View |
| 1 | National Grid | Michael J Ranalli | Negative | View |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Negative | View |

| | | | | |
|---|---|---|---|---|
| 1 | New York Power Authority | Ralph Rufrano | Negative | View |
| 1 | Northeast Utilities | David H. Boguslawski | Negative | View |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Abstain | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Abstain | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Negative | View |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Abstain | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Abstain | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Abstain | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Negative | View |
| 1 | Western Area Power Administration | Robert Temple | Abstain | View |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Abstain | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Negative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Negative | View |
| 2 | Midwest ISO, Inc. | Terry Bilke | Negative | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Abstain | |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | View |
| 3 | City of Tallahassee | Rusty S. Foster | Negative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Negative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Negative | View |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Negative | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Abstain | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Negative | View |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Negative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Negative | View |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Negative | View |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Negative | View |

| | | | | |
|---|---|---|---|---|
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Negative | View |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | View |
| 3 | Wisconsin Public Service Corp. | James A. Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Abstain | |
| 4 | Consumers Energy Co. | David Frank Ronk | Affirmative | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Negative | View |
| 4 | Indiana Municipal Power Agency | Gayle Mayo | Abstain | |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Negative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | View |
| 4 | WPS Resources Corp. | Christopher Plante | Negative | View |
| 5 | AEP Service Corp. | Brock Ondayko | Abstain | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | View |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Abstain | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Abstain | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Negative | View |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Negative | |
| 5 | New York Power Authority | Richard J. Ardolino | Negative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew E. Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Abstain | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Negative | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | View |
| 6 | AEP Marketing | Edward P. Cox | Abstain | |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | View |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Negative | View |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Negative | View |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Negative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Negative | |
| 6 | MidAmerican Energy Co. | Dennis Kimm | Affirmative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Negative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Abstain | |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Negative | View |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |

| | | | | |
|---|---|---|---|---|
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Negative | View |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Negative | View |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Utah Public Service Commission | Ric Campbell | Affirmative | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | View |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Negative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Negative | View |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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NERC NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Administration



| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC-TTC-CBM-MOD-008_in |
| **Ballot Period:** | 3/3/2008 - 3/12/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 176 |
| **Total Ballot Pool:** | 189 |
| **Quorum:** | **93.12 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 63.90 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 58 | 1 | 35 | 0.7 | 15 | 0.3 | 4 | 4 |
| 2 - Segment 2. | 10 | 0.9 | 6 | 0.6 | 3 | 0.3 | 0 | 1 |
| 3 - Segment 3. | 44 | 1 | 23 | 0.622 | 14 | 0.378 | 5 | 2 |
| 4 - Segment 4. | 7 | 0.5 | 2 | 0.2 | 3 | 0.3 | 2 | 0 |
| 5 - Segment 5. | 30 | 1 | 14 | 0.56 | 11 | 0.44 | 3 | 2 |
| 6 - Segment 6. | 25 | 1 | 12 | 0.571 | 9 | 0.429 | 2 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 6 | 0.5 | 5 | 0.5 | 0 | 0 | 1 | 0 |
| 10 - Segment 10. | 6 | 0.5 | 4 | 0.4 | 1 | 0.1 | 0 | 1 |
| **Totals** | **189** | **6.5** | **101** | **4.153** | **57** | **2.347** | **18** | **13** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | Negative | View |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Affirmative | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | View |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Manitoba Hydro | Michelle Rheault | Affirmative | |
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | |

| | | | | |
|---|---|---|---|---|
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Negative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Negative | View |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Negative | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Negative | View |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | |
| 3 | City of Tallahassee | Rusty S. Foster | Abstain | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Negative | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Negative | View |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Affirmative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Negative | View |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Abstain | |
| 3 | Wisconsin Public Service Corp. | James A. Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Affirmative | |
| 4 | Consumers Energy Co. | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Negative | View |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Negative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Abstain | |
| 4 | WPS Resources Corp. | Christopher Plante | Negative | View |
| 5 | AEP Service Corp. | Brock Ondayko | Negative | View |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Negative | View |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Affirmative | |
| 5 | New York Power Authority | Richard J. Ardolino | Affirmative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew E. Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Negative | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Abstain | |
| 6 | AEP Marketing | Edward P. Cox | Negative | View |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Negative | View |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Affirmative | |
| 6 | MidAmerican Energy Co. | Dennis Kimm | Affirmative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Affirmative | |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Utah Public Service Commission | Ric Campbell | Affirmative | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | View |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Administration



| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC-TTC-CBM-MOD-028_in |
| **Ballot Period:** | 3/3/2008 - 3/12/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 166 |
| **Total Ballot Pool:** | 179 |
| **Quorum:** | **92.74 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 63.05 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative | | Negative | | Abstain | No Vote |
|---|---|---|---|---|---|---|---|---|
| | | | # Votes | Fraction | # Votes | Fraction | # Votes | |
| 1 - Segment 1. | 53 | 1 | 25 | 0.694 | 11 | 0.306 | 13 | 4 |
| 2 - Segment 2. | 9 | 0.6 | 4 | 0.4 | 2 | 0.2 | 2 | 1 |
| 3 - Segment 3. | 43 | 1 | 19 | 0.655 | 10 | 0.345 | 12 | 2 |
| 4 - Segment 4. | 7 | 0.4 | 2 | 0.2 | 2 | 0.2 | 3 | 0 |
| 5 - Segment 5. | 29 | 1 | 8 | 0.5 | 8 | 0.5 | 11 | 2 |
| 6 - Segment 6. | 24 | 1 | 8 | 0.571 | 6 | 0.429 | 8 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 5 | 0.3 | 3 | 0.3 | 0 | 0 | 2 | 0 |
| 10 - Segment 10. | 6 | 0.5 | 4 | 0.4 | 1 | 0.1 | 0 | 1 |
| **Totals** | **179** | **5.9** | **73** | **3.72** | **41** | **2.18** | **52** | **13** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Avista Corp. | Scott Kinney | Abstain | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Abstain | |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Affirmative | View |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | View |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Abstain | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Abstain | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Abstain | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | View |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Abstain | |
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | View |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | View |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | View |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Abstain | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Negative | View |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Abstain | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Abstain | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Affirmative | |
| 1 | Western Area Power Administration | Robert Temple | Abstain | View |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Abstain | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | View |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Abstain | |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Abstain | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Abstain | |
| 3 | City of Tallahassee | Rusty S. Foster | Abstain | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | View |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Abstain | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Abstain | |
| 3 | Florida Municipal Power Agency | Michael Alexander | Negative | View |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Abstain | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Abstain | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | View |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Negative | View |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Abstain | |
| 3 | Wisconsin Public Service Corp. | James A. Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Affirmative | |
| 4 | Consumers Energy Co. | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Negative | View |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Negative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Abstain | |
| 4 | WPS Resources Corp. | Christopher Plante | Abstain | |
| 5 | AEP Service Corp. | Brock Ondayko | Abstain | |
| 5 | Avista Corp. | Edward F. Groce | Abstain | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Abstain | |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Affirmative | View |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Abstain | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Abstain | |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Negative | View |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Abstain | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Abstain | |
| 5 | New York Power Authority | Richard J. Ardolino | Affirmative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew E. Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Negative | View |
| 5 | Progress Energy Carolinas | Wayne Lewis | Abstain | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Abstain | |
| 6 | AEP Marketing | Edward P. Cox | Abstain | |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Abstain | |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | View |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Abstain | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Abstain | |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Abstain | |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Abstain | |
| 6 | MidAmerican Energy Co. | Dennis Kimm | Affirmative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Negative | View |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Abstain | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | View |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | View |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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NERC NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Administration

Registered Ballot Body
Ballot Events
Current Ballot Pools
Current Ballots
Previous Ballots
Vetting
Proxy Pool

| Ballot Results | |
|---|---|
| Ballot Name: | ATC-TTC-CBM-MOD-029_in |
| Ballot Period: | 3/3/2008 - 3/12/2008 |
| Ballot Type: | Initial |
| Total # Votes: | 169 |
| Total Ballot Pool: | 182 |
| Quorum: | 92.86 % The Quorum has been reached |
| Weighted Segment Vote: | 57.56 % |
| Ballot Results: | The standard will proceed to recirculation ballot. |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 55 | 1 | 25 | 0.61 | 16 | 0.39 | 10 | 4 |
| 2 - Segment 2. | 9 | 0.7 | 4 | 0.4 | 3 | 0.3 | 1 | 1 |
| 3 - Segment 3. | 43 | 1 | 18 | 0.667 | 9 | 0.333 | 14 | 2 |
| 4 - Segment 4. | 7 | 0.3 | 2 | 0.2 | 1 | 0.1 | 4 | 0 |
| 5 - Segment 5. | 29 | 1 | 9 | 0.563 | 7 | 0.438 | 11 | 2 |
| 6 - Segment 6. | 23 | 1 | 6 | 0.429 | 8 | 0.571 | 7 | 2 |
| 7 - Segment 7. | 1 | 0.1 | 1 | 0.1 | 0 | 0 | 0 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 7 | 0.6 | 4 | 0.4 | 2 | 0.2 | 1 | 0 |
| 10 - Segment 10. | 6 | 0.4 | 2 | 0.2 | 2 | 0.2 | 1 | 1 |
| **Totals** | **182** | **6.2** | **71** | **3.569** | **49** | **2.632** | **49** | **13** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | View |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Abstain | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Negative | View |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Affirmative | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Abstain | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Abstain | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Abstain | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Negative | View |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | View |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Abstain | |
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Affirmative | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Abstain | |
| 1 | National Grid | Michael J Ranalli | Negative | View |
| 1 | Nebraska Public Power District | Richard L. Koch | Abstain | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Negative | View |
| 1 | New York Power Authority | Ralph Rufrano | Negative | View |

| | | | | |
|---|---|---|---|---|
| 1 | Northeast Utilities | David H. Boguslawski | Negative | View |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | Iorees Tadros | | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Negative | View |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Negative | View |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Abstain | View |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Negative | View |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Abstain | |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | View |
| 3 | City of Tallahassee | Rusty S. Foster | Negative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Negative | View |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Negative | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Abstain | |
| 3 | Florida Municipal Power Agency | Michael Alexander | Abstain | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Abstain | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Abstain | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Abstain | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Abstain | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Abstain | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Negative | View |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Abstain | |
| 3 | Wisconsin Public Service Corp. | James A. Maenner | Abstain | |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Affirmative | |
| 4 | Consumers Energy Co. | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Abstain | |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Abstain | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 4 | WPS Resources Corp. | Christopher Plante | Abstain | |
| 5 | AEP Service Corp. | Brock Ondayko | Abstain | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | View |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Abstain | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Abstain | |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Abstain | |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Abstain | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Abstain | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Abstain | |
| 5 | New York Power Authority | Richard J. Ardolino | Negative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew E. Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Negative | View |
| 5 | Progress Energy Carolinas | Wayne Lewis | Abstain | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Abstain | |
| 6 | AEP Marketing | Edward P. Cox | Abstain | |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | View |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Negative | View |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Negative | View |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Abstain | |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Abstain | |
| 6 | Lincoln Electric System | Eric Ruskamp | Abstain | |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Abstain | |
| 6 | New York Power Authority | Thomas Papadopoulos | Negative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Negative | View |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Affirmative | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Negative | View |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Negative | View |

| | | | | |
|---|---|---|---|---|
| 9 | Oregon Public Utility Commission | Jerome Murray | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Utah Public Service Commission | Ric Campbell | Affirmative | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | View |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Abstain | View |
| 10 | New York State Reliability Council | Alan Adamson | Negative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Negative | View |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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Standards Administration



| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC-TTC-CBM-MOD-030_in |
| **Ballot Period:** | 3/3/2008 - 3/12/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 173 |
| **Total Ballot Pool:** | 186 |
| **Quorum:** | **93.01 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 44.19 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 56 | 1 | 15 | 0.395 | 23 | 0.605 | 14 | 4 |
| 2 - Segment 2. | 9 | 0.7 | 2 | 0.2 | 5 | 0.5 | 1 | 1 |
| 3 - Segment 3. | 44 | 1 | 18 | 0.545 | 15 | 0.455 | 9 | 2 |
| 4 - Segment 4. | 7 | 0.3 | 2 | 0.2 | 1 | 0.1 | 4 | 0 |
| 5 - Segment 5. | 30 | 1 | 10 | 0.455 | 12 | 0.545 | 6 | 2 |
| 6 - Segment 6. | 25 | 1 | 8 | 0.4 | 12 | 0.6 | 3 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 6 | 0.5 | 3 | 0.3 | 2 | 0.2 | 1 | 0 |
| 10 - Segment 10. | 6 | 0.5 | 2 | 0.2 | 3 | 0.3 | 0 | 1 |
| **Totals** | **186** | **6.1** | **60** | **2.695** | **74** | **3.405** | **39** | **13** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | Negative | View |
| 1 | Avista Corp. | Scott Kinney | Abstain | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Abstain | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Negative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Affirmative | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Abstain | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Negative | View |
| 1 | Idaho Power Company | Ronald D. Schellberg | Abstain | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | View |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Manitoba Hydro | Michelle Rheault | Affirmative | |
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Abstain | |
| 1 | National Grid | Michael J Ranalli | Negative | View |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | |

| | | | | |
|---|---|---|---|---|
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Negative | View |
| 1 | New York Power Authority | Ralph Rufrano | Negative | |
| 1 | Northeast Utilities | David H. Boguslawski | Negative | View |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Abstain | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Negative | View |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Negative | View |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Abstain | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Abstain | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Abstain | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Abstain | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Negative | View |
| 1 | Western Area Power Administration | Robert Temple | Abstain | View |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Abstain | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Negative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Negative | View |
| 2 | Midwest ISO, Inc. | Terry Bilke | Negative | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Abstain | |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Abstain | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Negative | View |
| 3 | City of Tallahassee | Rusty S. Foster | Negative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Negative | View |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Negative | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Abstain | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Affirmative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Abstain | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Negative | View |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Abstain | |
| 3 | Wisconsin Public Service Corp. | James A. Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Affirmative | |
| 4 | Consumers Energy Co. | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Abstain | |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Negative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Abstain | |
| 4 | WPS Resources Corp. | Christopher Plante | Abstain | |
| 5 | AEP Service Corp. | Brock Ondayko | Abstain | |
| 5 | Avista Corp. | Edward F. Groce | Abstain | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Negative | View |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Abstain | |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Affirmative | |
| 5 | New York Power Authority | Richard J. Ardolino | Negative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew E. Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Negative | View |
| 5 | Progress Energy Carolinas | Wayne Lewis | Negative | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Abstain | |
| 6 | AEP Marketing | Edward P. Cox | Abstain | |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Negative | View |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Negative | View |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Negative | View |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Affirmative | |
| 6 | MidAmerican Energy Co. | Dennis Kimm | Affirmative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Negative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Negative | View |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Abstain | |

| | | | | |
|---|---|---|---|---|
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Negative | View |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Negative | View |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Utah Public Service Commission | Ric Campbell | Affirmative | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Negative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Negative | View |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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116-390 Village Boulevard, Princeton, New Jersey 08540-5721

| Ballot Results | |
|---|---|
| Ballot Name: | ATC-TTC-CBM-MOD-001_in |
| Ballot Period: | 3/3/2008 - 3/12/2008 |
| Ballot Type: | Initial |
| Total # Votes: | 176 |
| Total Ballot Pool: | 189 |
| Quorum: | 93.12 % The Quorum has been reached |
| Weighted Segment Vote: | 59.63 % |
| Ballot Results: | The standard will proceed to recirculation ballot. |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 58 | 1 | 32 | 0.64 | 18 | 0.36 | 4 | 4 |
| 2 - Segment 2. | 10 | 0.9 | 5 | 0.5 | 4 | 0.4 | 0 | 1 |
| 3 - Segment 3. | 44 | 1 | 22 | 0.595 | 15 | 0.405 | 5 | 2 |
| 4 - Segment 4. | 7 | 0.5 | 2 | 0.2 | 3 | 0.3 | 2 | 0 |
| 5 - Segment 5. | 30 | 1 | 12 | 0.5 | 12 | 0.5 | 4 | 2 |
| 6 - Segment 6. | 25 | 1 | 10 | 0.5 | 10 | 0.5 | 3 | 2 |
| 7 - Segment 7. | 1 | 0.1 | 1 | 0.1 | 0 | 0 | 0 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 6 | 0.5 | 5 | 0.5 | 0 | 0 | 1 | 0 |
| 10 - Segment 10. | 6 | 0.5 | 4 | 0.4 | 1 | 0.1 | 0 | 1 |
| **Totals** | **189** | **6.6** | **93** | **3.935** | **64** | **2.665** | **19** | **13** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | Negative | View |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Negative | View |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Affirmative | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Affirmative | |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Manitoba Hydro | Michelle Rheault | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Affirmative | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Negative | View |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Abstain | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Negative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Negative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Negative | View |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Negative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Negative | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Negative | View |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Negative | View |
| 3 | City of Tallahassee | Rusty S. Foster | Abstain | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Negative | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Negative | View |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Negative | View |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Abstain | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Affirmative | |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Negative | View |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Negative | View |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Negative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Abstain | |
| 5 | AEP Service Corp. | Brock Ondayko | Negative | View |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Negative | View |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Negative | View |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Affirmative | |
| 5 | New York Power Authority | Richard J. Ardolino | Affirmative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Abstain | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Negative | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Abstain | |
| 6 | AEP Marketing | Edward P. Cox | Negative | View |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Negative | View |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Negative | View |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Affirmative | |
| 6 | MidAmerican Energy Co. | Dennis Kimm | Affirmative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 6 | PP&L, Inc. | Thomas Hyzinski | Abstain | |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Affirmative | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Utah Public Service Commission | Ric Campbell | Affirmative | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | View |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC-TTC-CBM-MOD-004_in |
| **Ballot Period:** | 3/3/2008 - 3/12/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 173 |
| **Total Ballot Pool:** | 186 |
| **Quorum:** | **93.01 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 38.80 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

**Summary of Ballot Results**

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 57 | 1 | 19 | 0.463 | 22 | 0.537 | 12 | 4 |
| 2 - Segment 2. | 10 | 0.8 | 3 | 0.3 | 5 | 0.5 | 1 | 1 |
| 3 - Segment 3. | 43 | 1 | 14 | 0.4 | 21 | 0.6 | 6 | 2 |
| 4 - Segment 4. | 8 | 0.6 | 2 | 0.2 | 4 | 0.4 | 2 | 0 |
| 5 - Segment 5. | 29 | 1 | 8 | 0.381 | 13 | 0.619 | 6 | 2 |
| 6 - Segment 6. | 24 | 1 | 5 | 0.278 | 13 | 0.722 | 4 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 6 | 0.5 | 3 | 0.3 | 2 | 0.2 | 1 | 0 |
| 10 - Segment 10. | 6 | 0.5 | 2 | 0.2 | 3 | 0.3 | 0 | 1 |
| **Totals** | **186** | **6.5** | **56** | **2.522** | **84** | **3.978** | **33** | **13** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | Affirmative | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | View |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Negative | View |
| 1 | Duke Energy Carolina | Douglas E. Hils | Abstain | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Abstain | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Negative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Negative | View |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | View |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Abstain | |

| | | | | |
|---|---|---|---|---|
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Negative | View |
| 1 | National Grid | Michael J Ranalli | Negative | View |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Negative | View |
| 1 | New York Power Authority | Ralph Rufrano | Negative | View |
| 1 | Northeast Utilities | David H. Boguslawski | Negative | View |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Abstain | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Abstain | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Negative | View |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Abstain | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Abstain | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Abstain | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Negative | View |
| 1 | Western Area Power Administration | Robert Temple | Abstain | View |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Abstain | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Negative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Negative | View |
| 2 | Midwest ISO, Inc. | Terry Bilke | Negative | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Abstain | |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | View |
| 3 | City of Tallahassee | Rusty S. Foster | Negative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Negative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Negative | View |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Negative | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Abstain | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Negative | View |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Negative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Negative | View |

| | | | | |
|---|---|---|---|---|
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Negative | View |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Negative | View |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Negative | View |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | View |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Abstain | |
| 4 | Consumers Energy | David Frank Ronk | Affirmative | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Negative | View |
| 4 | Indiana Municipal Power Agency | Gayle Mayo | Abstain | |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Negative | View |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Negative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | View |
| 5 | AEP Service Corp. | Brock Ondayko | Abstain | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | View |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Abstain | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Abstain | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Negative | View |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Negative | |
| 5 | New York Power Authority | Richard J. Ardolino | Negative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Abstain | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Negative | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | View |
| 6 | AEP Marketing | Edward P. Cox | Abstain | |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | View |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Negative | View |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Negative | View |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Negative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Negative | |
| 6 | MidAmerican Energy Co. | Dennis Kimm | Affirmative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Negative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Abstain | |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Negative | View |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Negative | View |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Negative | View |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Utah Public Service Commission | Ric Campbell | Affirmative | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | View |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Negative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Negative | View |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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Account Log-In/Register

| Ballot Results | |
|---|---|
| Ballot Name: | ATC-TTC-CBM-MOD-008_in |
| Ballot Period: | 3/3/2008 - 3/12/2008 |
| Ballot Type: | Initial |
| Total # Votes: | 176 |
| Total Ballot Pool: | 189 |
| Quorum: | 93.12 % The Quorum has been reached |
| Weighted Segment Vote: | 63.90 % |
| Ballot Results: | The standard will proceed to recirculation ballot. |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 58 | 1 | 35 | 0.7 | 15 | 0.3 | 4 | 4 |
| 2 - Segment 2. | 10 | 0.9 | 6 | 0.6 | 3 | 0.3 | 0 | 1 |
| 3 - Segment 3. | 44 | 1 | 23 | 0.622 | 14 | 0.378 | 5 | 2 |
| 4 - Segment 4. | 7 | 0.5 | 2 | 0.2 | 3 | 0.3 | 2 | 0 |
| 5 - Segment 5. | 30 | 1 | 14 | 0.56 | 11 | 0.44 | 3 | 2 |
| 6 - Segment 6. | 25 | 1 | 12 | 0.571 | 9 | 0.429 | 2 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 6 | 0.5 | 5 | 0.5 | 0 | 0 | 1 | 0 |
| 10 - Segment 10. | 6 | 0.5 | 4 | 0.4 | 1 | 0.1 | 0 | 1 |
| **Totals** | **189** | **6.5** | **101** | **4.153** | **57** | **2.347** | **18** | **13** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | Negative | View |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Affirmative | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | View |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Manitoba Hydro | Michelle Rheault | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Negative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Negative | View |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Negative | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Negative | View |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | |
| 3 | City of Tallahassee | Rusty S. Foster | Abstain | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Negative | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Negative | View |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Negative | View |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Abstain | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Affirmative | |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Negative | View |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Negative | View |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Negative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Abstain | |
| 5 | AEP Service Corp. | Brock Ondayko | Negative | View |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Negative | View |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Affirmative | |
| 5 | New York Power Authority | Richard J. Ardolino | Affirmative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Negative | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Abstain | |
| 6 | AEP Marketing | Edward P. Cox | Negative | View |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Negative | View |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Affirmative | |
| 6 | MidAmerican Energy Co. | Dennis Kimm | Affirmative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 6 | PP&L, Inc. | Thomas Hyzinski | Affirmative | |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Utah Public Service Commission | Ric Campbell | Affirmative | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | View |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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Account Log-In/Register

| Ballot Results | |
|---|---|
| Ballot Name: | ATC-TTC-CBM-MOD-028_in |
| Ballot Period: | 3/3/2008 - 3/12/2008 |
| Ballot Type: | Initial |
| Total # Votes: | 166 |
| Total Ballot Pool: | 179 |
| Quorum: | 92.74 % The Quorum has been reached |
| Weighted Segment Vote: | 63.05 % |
| Ballot Results: | The standard will proceed to recirculation ballot. |

**Summary of Ballot Results**

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 53 | 1 | 25 | 0.694 | 11 | 0.306 | 13 | 4 |
| 2 - Segment 2. | 9 | 0.6 | 4 | 0.4 | 2 | 0.2 | 2 | 1 |
| 3 - Segment 3. | 43 | 1 | 19 | 0.655 | 10 | 0.345 | 12 | 2 |
| 4 - Segment 4. | 7 | 0.4 | 2 | 0.2 | 2 | 0.2 | 3 | 0 |
| 5 - Segment 5. | 29 | 1 | 8 | 0.5 | 8 | 0.5 | 11 | 2 |
| 6 - Segment 6. | 24 | 1 | 8 | 0.571 | 6 | 0.429 | 8 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 5 | 0.3 | 3 | 0.3 | 0 | 0 | 2 | 0 |
| 10 - Segment 10. | 6 | 0.5 | 4 | 0.4 | 1 | 0.1 | 0 | 1 |
| **Totals** | **179** | **5.9** | **73** | **3.72** | **41** | **2.18** | **52** | **13** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Avista Corp. | Scott Kinney | Abstain | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Abstain | |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Affirmative | View |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | View |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Abstain | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Abstain | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Abstain | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | View |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Abstain | |
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |

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|---|---|---|---|---|
| 1 | National Grid | Michael J Ranalli | Affirmative | View |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | View |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | View |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Abstain | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Negative | View |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Abstain | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Abstain | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Affirmative | |
| 1 | Western Area Power Administration | Robert Temple | Abstain | View |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Abstain | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | View |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Abstain | |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Abstain | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Abstain | |
| 3 | City of Tallahassee | Rusty S. Foster | Abstain | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | View |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Abstain | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Abstain | |
| 3 | Florida Municipal Power Agency | Michael Alexander | Negative | View |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Abstain | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Abstain | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | View |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Negative | View |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Abstain | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Affirmative | |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Negative | View |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Abstain | |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Negative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Abstain | |
| 5 | AEP Service Corp. | Brock Ondayko | Abstain | |
| 5 | Avista Corp. | Edward F. Groce | Abstain | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Abstain | |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Affirmative | View |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Abstain | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Abstain | |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Negative | View |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Abstain | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Abstain | |
| 5 | New York Power Authority | Richard J. Ardolino | Affirmative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Negative | View |
| 5 | Progress Energy Carolinas | Wayne Lewis | Abstain | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Abstain | |
| 6 | AEP Marketing | Edward P. Cox | Abstain | |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Abstain | |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | View |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Abstain | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Abstain | |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Abstain | |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Abstain | |
| 6 | MidAmerican Energy Co. | Dennis Kimm | Affirmative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Negative | View |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |

| | | | | |
|---|---|---|---|---|
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Abstain | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | View |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | View |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

Legal and Privacy : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
*Washington Office:* 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

| Ballot Results | |
|---|---|
| Ballot Name: | ATC-TTC-CBM-MOD-029_in |
| Ballot Period: | 3/3/2008 - 3/12/2008 |
| Ballot Type: | Initial |
| Total # Votes: | 169 |
| Total Ballot Pool: | 182 |
| Quorum: | 92.86 % The Quorum has been reached |
| Weighted Segment Vote: | 57.56 % |
| Ballot Results: | The standard will proceed to recirculation ballot. |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative | | Negative | | Abstain | No Vote |
|---|---|---|---|---|---|---|---|---|
| | | | # Votes | Fraction | # Votes | Fraction | # Votes | |
| 1 - Segment 1. | 55 | 1 | 25 | 0.61 | 16 | 0.39 | 10 | 4 |
| 2 - Segment 2. | 9 | 0.7 | 4 | 0.4 | 3 | 0.3 | 1 | 1 |
| 3 - Segment 3. | 43 | 1 | 18 | 0.667 | 9 | 0.333 | 14 | 2 |
| 4 - Segment 4. | 7 | 0.3 | 2 | 0.2 | 1 | 0.1 | 4 | 0 |
| 5 - Segment 5. | 29 | 1 | 9 | 0.563 | 7 | 0.438 | 11 | 2 |
| 6 - Segment 6. | 23 | 1 | 6 | 0.429 | 8 | 0.571 | 7 | 2 |
| 7 - Segment 7. | 1 | 0.1 | 1 | 0.1 | 0 | 0 | 0 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 7 | 0.6 | 4 | 0.4 | 2 | 0.2 | 1 | 0 |
| 10 - Segment 10. | 6 | 0.4 | 2 | 0.2 | 2 | 0.2 | 1 | 1 |
| **Totals** | **182** | **6.2** | **71** | **3.569** | **49** | **2.632** | **49** | **13** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | View |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Abstain | |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Negative | View |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Affirmative | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Abstain | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Abstain | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Abstain | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Negative | View |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | View |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Abstain | |
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Affirmative | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Abstain | |

| | | | | |
|---|---|---|---|---|
| 1 | National Grid | Michael J Ranalli | Negative | View |
| 1 | Nebraska Public Power District | Richard L. Koch | Abstain | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Negative | View |
| 1 | New York Power Authority | Ralph Rufrano | Negative | View |
| 1 | Northeast Utilities | David H. Boguslawski | Negative | View |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Negative | View |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Negative | View |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Abstain | View |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Negative | View |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Abstain | |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | View |
| 3 | City of Tallahassee | Rusty S. Foster | Negative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Negative | View |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Negative | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Abstain | |
| 3 | Florida Municipal Power Agency | Michael Alexander | Abstain | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Abstain | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Abstain | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Abstain | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Abstain | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Abstain | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Negative | View |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |

| | | | | |
|---|---|---|---|---|
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Abstain | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Abstain | |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Affirmative | |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Abstain | |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Abstain | |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Abstain | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 5 | AEP Service Corp. | Brock Ondayko | Abstain | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | View |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Abstain | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Abstain | |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Abstain | |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Abstain | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Abstain | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Abstain | |
| 5 | New York Power Authority | Richard J. Ardolino | Negative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Negative | View |
| 5 | Progress Energy Carolinas | Wayne Lewis | Abstain | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Abstain | |
| 6 | AEP Marketing | Edward P. Cox | Abstain | |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | View |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Negative | View |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Negative | View |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Abstain | |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Abstain | |
| 6 | Lincoln Electric System | Eric Ruskamp | Abstain | |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Abstain | |
| 6 | New York Power Authority | Thomas Papadopoulos | Negative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Negative | View |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Negative | View |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Negative | View |
| 9 | Oregon Public Utility Commission | Jerome Murray | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Utah Public Service Commission | Ric Campbell | Affirmative | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | View |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Abstain | View |
| 10 | New York State Reliability Council | Alan Adamson | Negative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Negative | View |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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| Ballot Results | |
|---|---|
| Ballot Name: | ATC-TTC-CBM-MOD-030_in |
| Ballot Period: | 3/3/2008 - 3/12/2008 |
| Ballot Type: | Initial |
| Total # Votes: | 173 |
| Total Ballot Pool: | 186 |
| Quorum: | 93.01 % The Quorum has been reached |
| Weighted Segment Vote: | 44.19 % |
| Ballot Results: | The standard will proceed to recirculation ballot. |

**Summary of Ballot Results**

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 56 | 1 | 15 | 0.395 | 23 | 0.605 | 14 | 4 |
| 2 - Segment 2. | 9 | 0.7 | 2 | 0.2 | 5 | 0.5 | 1 | 1 |
| 3 - Segment 3. | 44 | 1 | 18 | 0.545 | 15 | 0.455 | 9 | 2 |
| 4 - Segment 4. | 7 | 0.3 | 2 | 0.2 | 1 | 0.1 | 4 | 0 |
| 5 - Segment 5. | 30 | 1 | 10 | 0.455 | 12 | 0.545 | 6 | 2 |
| 6 - Segment 6. | 25 | 1 | 8 | 0.4 | 12 | 0.6 | 3 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 2 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 1 |
| 9 - Segment 9. | 6 | 0.5 | 3 | 0.3 | 2 | 0.2 | 1 | 0 |
| 10 - Segment 10. | 6 | 0.5 | 2 | 0.2 | 3 | 0.3 | 0 | 1 |
| **Totals** | **186** | **6.1** | **60** | **2.695** | **74** | **3.405** | **39** | **13** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Allegheny Power | Rodney Phillips | Abstain | |
| 1 | American Transmission Company, LLC | Jason Shaver | | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | Negative | View |
| 1 | Avista Corp. | Scott Kinney | Abstain | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Abstain | |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Negative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | El Paso Electric Company | Dennis Malone | Affirmative | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Abstain | |
| 1 | Georgia Transmission Corporation | Harold Taylor, II | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Negative | View |
| 1 | Idaho Power Company | Ronald D. Schellberg | Abstain | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | View |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Manitoba Hydro | Michelle Rheault | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 1 | Metropolitan Water District of Southern California | Garry Chinn | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Abstain | |
| 1 | National Grid | Michael J Ranalli | Negative | View |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Negative | View |
| 1 | New York Power Authority | Ralph Rufrano | Negative | |
| 1 | Northeast Utilities | David H. Boguslawski | Negative | View |
| 1 | Ohio Valley Electric Corp. | Robert Mattey | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Affirmative | |
| 1 | Omaha Public Power District | lorees Tadros | | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | PacifiCorp | Robert Williams | Abstain | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Negative | View |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Negative | View |
| 1 | PP&L, Inc. | Ray Mammarella | Negative | View |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Negative | View |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Abstain | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SCE&G | Henry Delk, Jr. | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Abstain | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Abstain | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Abstain | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | | |
| 1 | Westar Energy | Allen Klassen | Negative | View |
| 1 | Western Area Power Administration | Robert Temple | Abstain | View |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Abstain | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Negative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Negative | View |
| 2 | Midwest ISO, Inc. | Terry Bilke | Negative | |
| 2 | New Brunswick System Operator | Alden Briggs | | |
| 2 | New York Independent System Operator | Gregory Campoli | Negative | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Negative | View |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Allegheny Power | Bob Reeping | Abstain | |
| 3 | American Electric Power | Raj Rana | Abstain | |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Abstain | |
| 3 | Atlantic City Electric Company | James V. Petrella | Negative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Negative | View |
| 3 | City of Tallahassee | Rusty S. Foster | Negative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Negative | View |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Negative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Negative | View |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Negative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Abstain | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Georgia System Operations Corporation | Edward W Pourciau | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Affirmative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Municipal Electric Authority of Georgia | Steven M. Jackson | Abstain | |

| | | | | |
|---|---|---|---|---|
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Negative | View |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Negative | View |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Abstain | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | American Public Power Association | Allen Mosher | Affirmative | |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Abstain | |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Abstain | |
| 4 | Madison Gas and Electric Co. | Joseph G. DePoorter | Negative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Abstain | |
| 5 | AEP Service Corp. | Brock Ondayko | Abstain | |
| 5 | Avista Corp. | Edward F. Groce | Abstain | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Negative | View |
| 5 | Calpine Corporation | John Brent Hebert | Negative | View |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Negative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Duke Energy | Robert Smith | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Abstain | |
| 5 | Florida Power & Light Co. | Robert A. Birch | | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Affirmative | |
| 5 | New York Power Authority | Richard J. Ardolino | Negative | |
| 5 | North Carolina Municipal Power Agency #1 | Matthew Schull | | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Negative | View |
| 5 | Progress Energy Carolinas | Wayne Lewis | Negative | |
| 5 | PSEG Power LLC | Thomas Piascik | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tampa Electric Co. | Frank L Busot | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Abstain | |
| 6 | AEP Marketing | Edward P. Cox | Abstain | |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Negative | View |
| 6 | Calpine Energy Services | Angela Easton | Negative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Negative | View |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Coral Power Corp. | Paul Benjamin Kerr | Negative | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Negative | View |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Affirmative | |
| 6 | MidAmerican Energy Co. | Dennis Kimm | Affirmative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Negative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Negative | View |
| 6 | PSEG Energy Resources & Trade LLC | James D. Hebson | Negative | View |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | | |

| | | | | |
|---|---|---|---|---|
| 6 | Sacramento Municipal Utility District | Robert D. Schwermann | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Abstain | |
| 7 | Metropolitan Water District of Southern California | Ernest Hahn | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | |
| 8 | Other | Michehl R. Gent | | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Negative | View |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Negative | View |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Abstain | |
| 9 | Utah Public Service Commission | Ric Campbell | Affirmative | |
| 9 | Wyoming Public Service Commission | Steve Oxley | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Negative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Negative | View |
| 10 | ReliabilityFirst Corporation | Jacquie Smith | | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC Conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Flowgate:**

1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

**Available Flowgate Capability (AFC):** A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system facilities removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for ATC Paths.

   **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate ATCs for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in AFC calculations including:

**R1.2.1.** Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

**R2.** The Transmission Operator shall perform the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R2.1.** Identify Flowgates used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated

Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use first Contingency assumptions consistent with those first Contingencies used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems.

2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.** Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use first Contingency assumptions consistent with those first Contingencies used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems.

2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.3.** Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. If the coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.
- The Transmission Operator may utilize distribution factors less than 5% if desired.

2.1.4.2. If the limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

**R2.2.** At a minimum, establish the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.

**R2.3.** At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested within thirty calendar days from the request.

**R2.4.** Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, establish the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and facilities161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority

associated with the Transmission Service Provider from which the power is to be received as the source.

- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the period calculated for the Transmission Service Provider’s area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.3, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider’s area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.1.2.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.2.2.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.

**R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

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[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{Fi}$** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC – ETC_{Fi} – ETC_{NFi} – CBM_{Si} – TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**$AFC_{NF}$** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.3, R3.4, and R5, at a minimum on the following frequency: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R10.1.** For hourly AFC, once per hour.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

**R11.** When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$\mathbf{TC = min(P)}$$

$$\mathbf{P = \{PTC_1, PTC_2, \ldots PTC_n\}}$$

$$PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either 'Available' or 'Total').

**P** is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

$\mathbf{PTC_n}$ is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n.*

$\mathbf{FC_n}$ is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

$\mathbf{DF_{np}}$ is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs) that it updated the TFCs for each Flowgate at least once per calendar year. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

**M13.** The TSP must be capable of demonstrating that for any calculation of firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the firm ETC for a specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R6)

**M14.** The TSP must be capable of demonstrating that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the non-firm ETC for a specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R7)

**M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

**M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated ATC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Transfer Capabilities follows the procedure described in R11. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Data Retention**

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the subrequirement is incomplete. | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the subrequirement is incomplete. | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). |
| R2. | The Transmission Operator established its list of internal Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.<br>**OR**<br>The Transmission Operator established its list of external Flowgates more than thirty days, but not more than sixty calendar days, following a request to create, modify or delete an external flowgate as described in R2.3.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven | The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator established its list of internal Flowgates more than three months late, but not more than six months late as described in R2.2.<br>**OR**<br>The Transmission Operator established its list of external Flowgates more than 60 calendar days, but not more than ninety calendar days, following a request to create, modify or delete an external | The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator established its list of internal Flowgates more than six months late, but not more than nine months late as described in R2.2.<br>**OR**<br>The Transmission Operator established its list of external Flowgates more than ninety days, but not more than 120 calendar days, following a request to create, modify or delete an external flowgate as | The Transmission Operator did not include six or more Flowgates in its AFC calculations that met the criteria described in R2.1.<br>**OR**<br>The Transmission Operator established its list of internal Flowgates more than nine months late as described in R2.2.<br>**OR**<br>The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.<br>**OR**<br>The Transmission Operator established its list of external |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | calendar days of their determination, but is has not been more than 14 calendar days since their determination. | flowgate as described in R2.3.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 calendar days of their determination, but is has not been more than 21 calendar days since their determination. | described in R2.3.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 calendar days of their determination, but is has not been more than 28 calendar days since their determination. | Flowgates more than 120 calendar days following a request to create, modify or delete an external flowgate as described in R2.3.<br>**OR**<br>The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.<br>**OR**<br>The Transmission Operator has not updated its list of internal Flowgates for two or more consecutive years.<br>**OR**<br>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.<br>**OR**<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update.<br>**OR**<br>The Transmission Operator has |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 calendar days of their determination. |
| R3. | The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used 11 to 20 Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used 21 to 30 Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used a Transmission model that had not been updated per the schedule specified in R3.<br><br>**OR**<br><br>The Transmission Operator used more than 30 Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>**OR**<br><br>The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br><br>**OR**<br><br>The Transmission operator did not include in the Transmission model detailed modeling data and topology at least three contiguous busses of the BES for more than one adjacent Reliability Coordinator area. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. |
| R4. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or more than 3 reservations, whichever is greater. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not use the model provided by the Transmission Operator.<br>**OR**<br>The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.<br>**OR**<br>The Transmission Service provider did not use AFC |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | provided by a third party. |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15 MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25 MW, whichever is greater.. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25 MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35 MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35 MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45 MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45 MW, whichever is greater. |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15 MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25 MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25 MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35 MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35 MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45 MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45 MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater). | than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |
| R10 | For Hourly, the Transmission Service provider did not calculate for more than 24 hours but not more than 48 hours.<br>**OR**<br>For Daily, the Transmission Service provider did not calculate for more than 7 calendar days but not more than 14 calendar days.<br>**OR**<br>For Monthly, the Transmission Service provider did not calculate for 31 or more | For Hourly, the Transmission Service provider did not calculate for more than 48 hours but not more than 72 hours.<br>**OR**<br>For Daily, the Transmission Service provider did not calculate for more than 14 calendar days but not more than 21 calendar days.<br>**OR**<br>For Monthly, the Transmission Service provider did not calculate for 60 or more | For Hourly, the Transmission Service provider did not calculate for more than 72 hours but not more than 96 hours.<br>**OR**<br>For Daily, the Transmission Service provider did not calculate for more than 21 calendar days but not more than 28 calendar days.<br>**OR**<br>For Monthly, the Transmission Service provider did not calculate for 90 or more | For Hourly, the Transmission Service provider did not calculate for more than 96 hours.<br>**OR**<br>For Daily, the Transmission Service provider did not calculate for more than 28 calendar days.<br>**OR**<br>For Monthly, the Transmission Service provider did not calculate for 120 or more calendar days. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | calendar days, but less than 60 calendar days. | calendar days, but less than 90 calendar days. | calendar days, but less than 120 calendar days. | |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R11. |

## E. Regional Variances

None.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC Conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Flowgate:**

1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

**Available Flowgate Capability (AFC):** A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less ~~existing~~ Existing ~~t~~Transmission ~~c~~Commitments (~~including retail customer service~~ETC), less a Capacity Benefit Margin, ~~and~~ less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system facilities removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs ~~are~~ can be used to determine Available Transfer Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for ATC Paths.

   **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate ATCs for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) are approved by all applicable regulatory authorities~~, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees~~.

## B. Requirements

**R1.** The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID). ***[****Violation Risk Factor: Lower****]*** ***[****Time Horizon: Operations Planning****]***

**R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in ~~ATC~~ AFC calculations including:

**R1.2.1.** Define if the source used for ~~ATC~~ AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for ~~ATC~~ AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider's ~~ATC~~ AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

**R2.** The Transmission Operator shall perform the following: ***[****Violation Risk Factor: Lower~~Medium~~****]*** ***[****Time Horizon: Operations Planning****]***

**R2.1.** Identify Flowgates used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements~~/~~ and their worst associated ~~Contingency~~ Contingency combinations with an OTDF ~~greater than 3~~of at least 5% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use first Contingency assumptions consistent with those first Contingencies used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems.

2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.** Results of a first C~~c~~ontingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements~~/~~ and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) ~~greater than 3~~of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use first Contingency assumptions consistent with those first Contingen~~en~~cies used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems.

2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.3.** Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.

**R2.1.4.** Any limiting E~~e~~lement/~~c~~Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. If the coordination of the limiting E~~e~~lement/~~c~~Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

2.1.4.2. If the limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

**R2.2.** At a minimum, ~~update~~ establish the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.

**R2.3.** At a minimum, ~~update~~establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested within thirty calendar days from the request.

**R2.4.** ~~Determine~~ Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, ~~update~~ establish the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the ~~updated~~ TFCs within seven calendar days of their ~~determination~~establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: *[Violation Risk Factor: Lower~~Medium~~] [Time Horizon: Operations Planning]*

**R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the ~~Transmission Owners and~~ Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and facilities161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation

in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: ***[****Violation Risk Factor: Lower~~Medium~~****]*** ***[****Time Horizon: Operations Planning****]***

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include ~~all~~ in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the period calculated for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.3, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: ***[****Violation Risk Factor: Lower~~Medium~~****]*** ***[****Time Horizon: Operations Planning****]***

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of ~~base~~ generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, ~~all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed,~~ based on:

~~R6.1.1.For on-peak intra-day and on-peak next-day AFCs:~~

~~6.1.1.1.~~**R6.1.1.** Load forecast for the ~~on-peak~~time period being calculated, ~~consistent with that used for planning and operations for applicable time periods,~~ including Native Load and ~~n~~Network S~~s~~ervice ~~L~~load

~~6.1.1.2.~~**R6.1.2.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run as~~, as they are expected to run as~~ specified ~~by~~ in the Transmission Service Provider's ATCID.

~~R6.1.4.For off-peak intra-day and off-peak next-day AFCs:~~

~~6.1.4.1.Load forecast for the off-peak period calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load.~~

~~6.1.4.2.Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.~~

~~R6.1.5.For days two through 31AFCs:~~

~~6.1.5.1.Load forecast for the day calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load.~~

~~6.1.5.2.Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.~~

~~R6.1.6.For months two through 13 AFCs:~~

~~6.1.6.1.Load forecast for the month calculated, consistent with that used for planning and operations for applicable time periods, including Native Load and network service Load.~~

~~6.1.6.2.Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run as specified by the Transmission Service Provider's ATCID.~~

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of ~~base~~ generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.2.2.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area ~~not included in the model~~.

**R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts~~, not included in the model and~~ having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area ~~not included in the model~~.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that ~~are not included in the model and having~~have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: ***[****Violation Risk Factor: Lower****]*** ***[****Time Horizon: Operations Planning****]***

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled ~~that are not included in the model~~ for the Transmission Service Provider's area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that ~~are not included in the model and~~ have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow ~~that are not included in the model~~ for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that ~~are not included in the model and~~ have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider for all adjacent Transmission Service Providers, and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower~~Medium~~] [Time Horizon: Operations Planning]*

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + \cancel{Counterflow}counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of ~~Firm~~ Transmission Service for that period, as defined in Business Practices.

~~**Counterflow**~~**counterflows$_{Fi}$** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + \cancel{Counterflow}counterflows$$

**Where:**

~~**$ATC_{NF}$**~~ **$AFC_{NF}$** is the non-firm Available Flowgate Capability for the ~~ATC Path~~Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of ~~Non-Firm~~ Transmission Service for that period, as defined in Business Practices.

~~**Counterflow**~~**counterflows$_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.3, R3.4, and R5, ~~-~~at a minimum on the following frequency: ***[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]***

**R10.1.** For hourly AFC, once per ~~day~~hour.

**R10.2.** For daily AFC, once per ~~week~~day.

**R10.3.** For monthly ~~ATC~~AFC, once ~~a~~ per ~~month~~week.

**R11.** When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$\mathbf{TC = min(P)}$$

$$\mathbf{P = \{PTC_1, PTC_2, \ldots PTC_n\}}$$

$$PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either 'Available' or 'Total').

**P** is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider~~3%~~ on an OTDF Flowgate or PTDF Flowgate.

$\mathbf{PTC_n}$ is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n*.

$\mathbf{FC_n}$ is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

$\mathbf{DF_{np}}$ is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**M5.** The Transmission Operator shall provide evidence (such as data ~~and~~ or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs) that it updated the TFCs for each Flowgate at least once per calendar year. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

**M13.** The TSP must be capable of demonstrating that for any calculation of firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the firm ETC for a specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R6)

**M14.** The TSP must be capable of demonstrating that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the non-firm ETC for a specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R7)

**M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

**M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

~~**M13.**The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ETC included the elements described in R6. (R6)~~

~~**M14.**The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ETC included the elements described in R7. (R7)~~

~~**M15.**The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm AFC used the algorithm and the elements described in R8 and~~

~~did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R8)~~

~~**M16.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm AFC used the algorithm and the elements described in R9 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R9)~~

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated ATC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of Transfer Capabilities follows the procedure described in R11. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to to determine flowgates and ~~calculate~~ T~~T~~FC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate ~~TTC~~ AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, ~~R6, R7,~~ R8, R9, R10, and R1~~0~~1 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits

- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | ~~N/A~~The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.<br><br>~~N/A~~ | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br><br>OR<br><br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).~~.~~ |
| R2. | The Transmission Operator established its list of internal Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.<br><br>OR<br><br>The Transmission Operator ~~has not updated~~ established its list of external Flowgates ~~for more than two consecutive quarters but not more than three consecutive quarters~~more than thirty days, but not more than sixty calendar days, following a request to create, modify or delete an external flowgate as | The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br><br>OR<br><br>The Transmission Operator established its list of internal Flowgates more than three months late, but not more than six months late as described in R2.2.<br><br>OR<br><br>The Transmission Operator established its list of external Flowgates more than ~~sixty~~60 calendar days, but not more than ninety calendar days, following a request to create, | The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br><br>OR<br><br>The Transmission Operator established its list of internal Flowgates more than six months late, but not more than nine months late as described in R2.2.<br><br>OR<br><br>The Transmission Operator established its list of external Flowgates more than ninety days, but not more than 120 | The Transmission Operator did not include six or more Flowgates in ~~their~~ its AFC calculations that met the criteria described in R2.1.<br><br>OR<br><br>The Transmission Operator established its list of internal Flowgates more than nine months late as described in R2.2.<br><br>OR<br><br>The Transmission Operator did not establish its list of internal Flowgates as described in R2.2. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | described in R2.3.<br>OR<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven calendar days ~~(one week)~~ of their determination, but is has not been more than 14 calendar days ~~(two weeks)~~ since their determination. | modify or delete an external flowgate as described in R2.3.<br>~~The Transmission Operator has not updated its list of external Flowgates for more than three but not more than four consecutive quarters.~~<br>OR<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>OR<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 calendar days ~~(two weeks)~~ of their determination, but is has not been more than 21 calendar days ~~(three weeks)~~ since their determination. | calendar days, following a request to create, modify or delete an external flowgate as described in R2.3.<br>~~The Transmission Operator has not updated its list of external Flowgates for more than four but not more than five consecutive quarters.~~<br>OR<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>OR<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 calendar days ~~(three weeks)~~ of their determination, but is has not been more than 28 calendar days ~~(four weeks)~~ since their determination. | OR<br>The Transmission Operator established its list of external Flowgates more than 120 calendar days following a request to create, modify or delete an external flowgate as described in R2.3.<br>OR<br>The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.<br>~~The Transmission Operator has not updated its list of external Flowgates for more than five consecutive quarters.~~<br>OR<br>The Transmission Operator has not updated its list of internal Flowgates for two or more consecutive years.<br>OR |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
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| | | | | The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.<br>OR<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update.<br>OR<br>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 calendar days ~~(4 weeks)~~ ~~of~~ their determination. |
| R3. | The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless | The Transmission Operator used ~~eleven~~ 11 to ~~twenty~~ 20 Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error | The Transmission Operator used ~~twenty-one~~21 to ~~thirty~~ 30 Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error | The Transmission Operator ~~did~~used a Transmission model that had been ~~not~~ updated ~~the Transmission model~~ per the schedule specified in R3.<br>OR<br>The Transmission Operator used more than ~~thirty~~ 30 Facility Ratings that were different from those specified by a Transmission or |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | how many times that error has been modeled. | has been modeled. | has been modeled. | Generator Owner in their Transmission model.<br>OR<br>The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>OR<br>The Transmission operator did not include in the Transmission model detailed modeling data and topology at least three contiguous busses of the BES for more than one adjacent Reliability Coordinator area.<br><br>Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled. |
| R4. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than 5% of all | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than 10% of all | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than 15% of all | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or more than 3 |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | reservations; or more than zero, but not more than 1 reservation, whichever is greater.~~.~~ ~~N/A~~ | reservations; or more than 1, but not more than 2 reservations, whichever is greater.~~.~~ ~~N/A~~ | reservations; or more than 2, but not more than 3 reservations, whichever is greater.~~.~~ ~~N/A~~ | reservations, whichever is greater.~~.~~ |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not use the model provided by the Transmission Operator.<br>OR<br>The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.<br>OR<br>The Transmission Service provider did not use AFC provided by a third party. |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15 MW, | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25 MW, | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35 MW, | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45 MW, |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | whichever is greater, but not more than 25% of the value calculated in the measure or 25 MW, whichever is greater..~~N/A~~ | whichever is greater, but not more than 35% of the value calculated in the measure or 35 MW, whichever is greater. ~~N/A~~ | whichever is greater, but not more than 45% of the value calculated in the measure or 45 MW, whichever is greater. ~~N/A~~ | whichever is greater.~~The Transmission Service Provider did not use all the elements defined in R6 when determining non-firm ETC, or used additional elements.~~ |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15 MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25 MW, whichever is greater.~~N/A~~ | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25 MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35 MW, whichever is greater.~~N/A~~ | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35 MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45 MW, whichever is greater. ~~N/A~~ | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45 MW, whichever is greater.~~The Transmission Service Provider did not use all the elements defined in R7 when determining firm AFC, or used additional elements.~~ |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).<br>~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).~~The Transmission Service Provider did not use all the elements defined in R8~~ |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | ~~N/A~~ | ~~when determining non-firm AFC, or used additional elements.~~ |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).<br><br>~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).<br><br>~~The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R9.~~ |
| R10 | For Hourly, the Transmission Service provider did not calculate for more than 24 hours but not more than 48 hours.<br><br>OR<br><br>For Daily, the Transmission Service provider did not calculate for more than 7 calendar days but not more than 14 calendar days.<br><br>OR<br><br>For Monthly, the Transmission Service | For Hourly, the Transmission Service provider did not calculate for more than 48 hours but not more than 72 hours.<br><br>OR<br><br>For Daily, the Transmission Service provider did not calculate for more than 14 calendar days but not more than 21 calendar days.<br><br>OR<br><br>For Monthly, the Transmission Service | For Hourly, the Transmission Service provider did not calculate for more than 72 hours but not more than 96 hours.<br><br>OR<br><br>For Daily, the Transmission Service provider did not calculate for more than 21 calendar days but not more than 28 calendar days.<br><br>OR<br><br>For Monthly, the | For Hourly, the Transmission Service provider did not calculate for more than 96 hours.<br><br>OR<br><br>For Daily, the Transmission Service provider did not calculate for more than 28 calendar days.<br><br>OR<br><br>For Monthly, the Transmission Service provider did not calculate for 120 or more calendar days. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | provider did not calculate for 31 or more calendar days, but less than 60 calendar days. | provider did not calculate for 60 or more calendar days, but less than 90 calendar days. | Transmission Service provider did not calculate for 90 or more calendar days, but less than 120 calendar days. | |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for determining Transfer Capabilities described in R11. |

## E. Regional Variances

None.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
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# Implementation Plan for Standard MOD-030-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-030-1 — Flowgate Methodology, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining AFC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Retired Standards

FAC-012-1 — Transfer Capability Methodology includes four requirements. MOD-030-1 incorporates the following requirements from FAC-012-1:

– R1 (Documentation of the Transfer Capability Methodology).

– R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

– R4 (Responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired.

FAC-013-1 — Establish and Communicate Transfer Capabilities, includes two requirements. MOD-030-1 incorporates the following requirements from FAC-013-1:

– R1 (Calculation of the Transfer Capabilities).

– R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-030-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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## Implementation Plan for Standard MOD-030-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-030-1 — Flowgate Methodology, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining ~~ATC~~AFC.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### ~~Modified~~ Retired Standards

FAC-012-1 — Transfer Capability Methodology includes four requirements. MOD-030-1 ~~This standard~~ incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology).
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (Responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired.

FAC-013-1 — Establish and Communicate Transfer Capabilities, includes two requirements. MOD-030-1 ~~This standard~~ incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-~~012~~ 013-1 is no longer needed and is being retired.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-030-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities~~, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001, MOD-028, MOD-029, and MOD-030 are approved by the NERC Board of Trustees~~. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

Please **DO NOT** use this form to submit comments on the current draft of MOD-030. Comments must be submitted by **May 15, 2008.**

If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-452-8060.

## Background Information — MOD-030 — Flowgate Methodology

(A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.)

An initial ballot of MOD-030-1 — Flowgate Methodology was conducted March 3-12, 2008 and there were several suggestions for modifying the standard that were submitted with ballots. The drafting team withdrew the standard from the ballot process, and made several changes to the standard based on stakeholder comments, including the following:

1. Clarified that MOD-030 does not require conversion of AFC to ATC. While the OASIS Requirements require that ATC be posted, the Drafting Team could not find any reason that AFC must be converted to ATC for reliability. MOD-030 continues to provide the equation to convert AFC to ATC, that shall be used 'when' the conversion occurs, but the NERC standards do not define 'when' that conversion must occur.
2. Changed several VRFs from "Medium" to "Lower" in response to industry comments. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
3. Applied a more graded approach to the VSLs where appropriate.
4. During the review of the VSLs and Measures, it was determined that the measures for R6, R7, R8, and R9 did not adequately measure compliance with the requirements. The drafting team updated the measures and VSLs to ensure that they captured the need to have accurate and valid numbers used in the requirements.
5. The standard drafting team has added language to 2.1.1 and 2.1.2 to clarify what is meant by first three limiting element/contingency combinations.
6. The SDT has modified R2.1.1.1 and R2.1.2.1 to respond to the suggestions to acknowledge the use of SPS and has added a new R2.1.4.2 to further define a "credible" limiting Element/Contingency combinations that may be requested for inclusion.
7. The Drafting Team has modified the subrequirements in R2 to change all uses of "3%" to "5%."

**Please review the revised version of MOD-030 and then answer the following questions. You do not have to answer all questions. Enter All Comments in Simple Text Format.**

1. **The drafting team modified some requirements and associated measures in MOD-030 to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct.**

   Incorrect Requirement(s) or Measure(s):

2. **The drafting team has modified the Violation Risk Factors for MOD-030 to reflect industry concerns that they did not match NERC's VRF definitions. NERC's VRF definitions are listed below:**

   **High Risk Requirement**:
   (a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or
   (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

   **Medium Risk Requirement**:
   (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or
   (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

   **Lower Risk Requirement**: is administrative in nature and
   (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or
   (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

   **Are the current VRFs established correctly?**

   ☐ Yes

☐ No

**If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.**
Comments:

3. **The drafting team has modified the Violation Severity Levels for MOD-030 to reflect industry concerns that they were too "pass/fail" oriented. Are the current VSLs established correctly?**

   ☐ Yes
   ☐ No

   **If "No," please identify specific VSLs and suggest changes to the language.**
   Comments:

4. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-030.**

   Comments:

Newsroom Site Map Contact NERC

| | Individual or group. | Name | Organization | Group Name | Lead Contact | Contact Organization | Question 1 | Question 2 | Question 2 Comments | Question 3 | Question 3 Comments | Question 4 Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Group | | | SERC ATCWG | Doug Bailey | Tennessee Valley Authority | | Yes | | Yes | | |
| | Group | | | WECC Market Interface Committee / Sub Commtt? ATC Task Force | W. Shannon Black | SMUD | MOD-30, M13 and M14 as drafted require the TSP to be "capable" of demonstration but do not require actual demonstration. The WECC Team suggests a minor rewrite to state, "The TSP shall demonstrate that..." This shifts the measurement from the TSP's mere capability to an actual performance. | Yes | | Yes | | Should the term "dispatch order" in MOD-30, R6.1.2 be a capitalized defined term? |
| | Individual | Jack Cashin/Barry Green | EPSA | | | | Through this revision process, some of the MOD standards have included an explicit requirement for consistency between planning assumptions and modeling assumptions used in calculation of ATC. In particular, requirement 6.1 of the previous version of MOD 030 included such a requirement and we believe it should be retained. | | No comment | | no comment | no comment |
| | Individual | Jim Useldinger | Kansas City Power & Light | | | | The Transmission Service Provider should be added along with the TOP for these functions in all requirements. | Yes | | Yes | | |
| | Individual | Paul Rocha | CenterPoint Energy | | | | | | | | | The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | single control area. |
| | Group | | | WECC Market Interface Committee ATC Task Force | W. Shannon Black | SMUD | MOD-30, M13 and M14 as drafted require the TSP to be "capable" of demonstration but do not require actual demonstration. The WECC Team suggests a minor rewrite to state, "The TSP shall demonstrate that..." This shifts the measurement from the TSP's mere capability to an actual performance. | Yes | | Yes | | Should the term "dispatch order" in MOD-030, R6.1.2 be a capitalized defined term? |
| | Individual | H. Steven Myers | ERCOT ISO | | | | Requirement 1: I suggest modifying the requirement to state: "The Transmission Service Provider with ATC Path(s) shall include in its “Available Transfer Capability Implementation Document” (ATCID)." Requirement 2: I suggest modifying the requirement to state: "The Transmission Operator with ATC Path(s) shall perform the following:" Requirement 3: I suggest modifying the requirement to state: "The Transmission Operator with ATC Path(s) shall make available to the Transmission Service Provider with ATC Path(s) a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria:" Requirement 4: I suggest modifying the requirement to state: "When calculating AFCs, the Transmission Service Provider with ATC Path(s) shall represent the impact of Transmission Service as follows:" Requirement 5: I suggest modifying the requirement to state: "When calculating AFCs, the Transmission Service Provider with ATC Path(s) shall:" Requirement 6: I suggest modifying the requirement to state: "When calculating the impact of ETC for firm commitments (ETCFi) for all time periods for a Flowgate, the Transmission Service Provider with ATC Path(s) shall sum the following:" Requirement 7: I suggest modifying the requirement to state: "When calculating the impact of ETC for non-firm commitments (ETCNFi) for all time periods for a Flowgate the Transmission Service Provider with ATC Path (s) shall sum:" Requirement 8: I suggest modifying the requirement to state: "When calculating firm AFC for a | | | | | I suggest modifying the Applicability section to state: "4.1.1 Each Transmission Operator with ATC Path(s) that uses the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for ATC Paths." "4.1.2 Each Transmission Service Provider with ATC Path(s) that uses the Flowgate Methodology to calculate ATCs for ATC Paths." |

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| | | | | | | | Flowgate for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:" Requirement 9: I suggest modifying the requirement to state: "When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:" Requirement 10: I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path (s) shall recalculate AFC, utilizing the updated models described in R3.3, R3.4, and R5, at a minimum on the following frequency:" Requirement 11: I suggest modifying the requirement to state: "When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider with ATC Path(s) shall convert those values based on the following algorithm:" | | | | | |
| | Individual | Frank Cumpton | California ISO | | | | | | | | | R 3 – Should the actual Flowgate model made available to TSP upon request ONLY under NDA??? Confidential Model and access??? R 11 – SDT should clarify that MOD 30 R11 only specifies HOW AFC be converted and DOES NOT REQUIRE that it must be converted, as intent of SDT. MOD 30 does not REQUIRE that all AFCs be converted and posted to OASIS, irrespective of whether or not the ATC Path definition applies to internal lines for those with a flow based model. |
| | Individual | Maria Neufeld | Manitoba Hydro | | | | | Yes | | Yes | | MH echoes the concerns raised and documented by MISO that MOD-030 requirements are generally more stringent than those outlined for MOD-028 and MOD-029. |
| | Group | | | NPCC Regional Standards Committee | Guy V. Zito | Northeast Power Coordinating Council | None | Yes | | Yes | | |
| | | | | | | | Requirement 2, Applicable Entity: FE believes that this requirement and its associated sub-requirements are incorrectly assigned to the Transmission Operator. In reviewing the presently approved Functional Model (FM) Version 3 and its associated Technical Document, the determination of total transfer capability clearly falls to | | | | | |

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| | Group | | | FirstEnergy | Doug Hohlbaugh | FirstEnergy Corp. | a planning function. In FM Version 3, task 3c of the Function – Planning Reliability states "Review and determine total transfer capability (generally one year and beyond) as appropriate." This is the only area that explicitly states "determine" as it relates to total transfer capability. The FM Version 3 later describes the responsibilities of the Planning Coordinators and Transmission Planners as having a role in coordinating total transfer capability. Nowhere within the Functional Model is this assignment relegated to the real-time aspect of the Transmission Operator. Additionally, since R2.5 allows the responsible entity to establish Total Flowgate Capabilities once per year, it would seem reasonable that this would be applicable to a planning function. FirstEnergy believes the appropriate responsible entity is the Planning Coordinator or Transmission Planner since this entity would likely have the same wide-area view that is covered by the corresponding Transmission Service Provider who is determining the Available Flowgate Capacity. Assigning the determination of total transfer capability to the Planning Coordinator would also better align the standard for implementation within the RTO construct as well as non-market areas. The tasks described within R2 are completed by FE's RTO organizations – MISO and PJM – for the transmission facilities owned and operated by FirstEnergy. The standard should not be written in a way that would knowingly require some sort of delegation assignment for a large portion of the transmission system. R2 - MOD-030 does not appear to be consistent with MOD-028 and MOD-029 with respect to the criterion on which contingencies must be analyzed to determine Total Transfer Capability. In MOD-030 R2 is very prescriptive on how TFC is determined with regard to the contingencies that must be analyzed and the distribution factor thresholds that lead to a flowgate definition. However, MOD-028 and MOD-029 simply require the ATCID to | Yes | FE supports the SDT's adjustment of VRFs such that no VRF within the ATC standards exceeds a "Lower" rating. We concur with the team's reasoning and rationale provided in response to ballot comments in making this change. | No | In the Severe category VSLs for requirement R3, we suggest removing the word "detailed" when referring to detailed modeling data as it is ambiguous and subjective. | FirstEnergy appreciates the Standard Drafting Team's decision to move to a formal comment period based on the prior initial ballot feedback. We commend the team for moving quickly to respond to the ballot comments and providing the industry a revised set of standards to review and comment. We suggest striking the words "short term use" from the purpose statement as we believe this methodology should also be valid in the planning horizon as a longer term projection of TFC and AFC. Regarding the revision to the Effective Date, while FirstEnergy agrees that there is a need to ensure that the standard is implemented consistently across the entire continent we are concerned with the Effective Date being subject to approval of ALL regulatory authorities. We believe an appropriate Implementation Plan should reflect a period of time beyond the NERC Board of Trustee approval date that would reflect when the requirements are considered mandatory and enforceable. The timeline should allow sufficient time for regulatory authority reviews, with the intent of sanctions also being enforced in conjunction with the conclusion of the implementation period. However, a delay from a given regulatory agency should not impact when the requirements are considered mandatory and enforceable for the bulk electric system. |

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| | | | | | | | describe the "how". For example, in MOD-028 R1.4 states that the ATCID include "A description of the manner in which Contingencies are identified for use in the TTC [Total Transfer Capability] process." FE suggest changes are needed to R2 to align with the MOD-028 and MOD-029 standards. R2.4 – The first bullet of R2.4 should state that when a TFC is based on a thermal rating that it reflects the lowest facility rating for the monitored facility(ies) considered in the flowgate. The reference to the SOL should be reserved to only the second bullet which would appropriately account for a voltage or stability limit. R10 – As stated in FE's MOD-001 comments, it is suggested that the requirements for frequency of recalculating ATC be dealt with in MOD-001 (R8) to ensure a consistent application across MOD-028, MOD-029 and MOD-030 that presently does not exist. If MOD-001 R8 is revised as suggested, R10 in MOD-030 can be deleted. | | | | | |
| | Individual | Thad Ness | AEP | | | | | | | | | The Purpose statement is unclear and perhaps nonsensical. Is the purpose "to increase consistency and reliability in the development of documentation…." or "to support analysis and system operation"? What entities' "short term use"? Suggestion: Purpose: To ensure consistency of calculation of those entities employing Flowgate Methodology pursuant to MOD-001 R1. |
| | Group | | | Public Service Commission of South Carolina | Phil Riley | Public Service Commission of South Carolina | | Yes | | Yes | | |
| | | | | | | | Requirement 1 • Add to the end of R1 "provided that the data is not market sensitive." Requirement 2 • R2.1.3 – The interconnection wide congestion management procedures should be listed for each Interconnection. For the Eastern Interconnection this is the TLR process. Requirement 3 • R3.2 and R3.3 -The update frequency for AFC calculations should be addressed by NAESB Business Practices. • R3.4 – The last sentence in R3. 4 should be replaced with; "Equivalent representation of radial lines and facilities is allowed consistent | | PJM supports | | NERC states that a VSL defines the degree to which | |

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| | Individual | Patrick Brown | PJM | | | | with the Bulk Electric System standards." Requirement 5 • R5.2 - R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD-001and applied consistently across MODS 28, 29 and 30. Requirement 6 • R6.3 - PJM understands the SDT's reasons for using "Confirmed" reservations in accordance with the FERC regulations. Reservations that are in "Accepted", as well as, "Confirmed" status should be included. Once service is "Accepted" by a TP it cannot be retracted. Using reservations that are in "Accepted" and "Confirmed" status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TP from decrementing for accepted and confirmed TSRs. We understand that some TPs maintain two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TPs who maintain two sets of ATC values to post the "internal" ATC values to provide greater transparency and give customers a more accurate picture of capability available to new requests. Requirements 7 and 9 • R7 and R9 Non-firm should be removed from this Reliability Standard and be considered NAESB scope. Requirement 10 • The periodic requirements of R10 are NAESB scope. This requirement should be eliminated. | Yes | NERC's position to revise all Violation Risk Factors to have an assigned risk factor of "Lower." A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. | No | compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations –this language to be added to the standard. Add a new item 6 to section A of MOD-001. For example a review of MOD-001 R2 and R8 and MOD-30 R10 should be performed for determination of multiple violations resulting from one event. | The MOD standards extend into areas that should be covered and addressed by NAESB Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices, and not included in the NERC Standards as reliability based requirements (see specific details for MOD-001 R2 and R7 and MOD-030 R10 in the Specific Comments sections below). Non-firm should be removed from this reliability standard. • Reservations in "Accepted", as well as, "Confirmed" status should be included in ATC calculation (see MOD030 R6.3). Once the transmission provider has accepted the request, the provider is now required to provide service; therefore, not decrementing for accepted TSRs could result in over commitment. |
| | Individual | Greg Rowland | Duke Energy Corporation | | | | R1 – Need to ensure that comparable information should be required in either the study report or the ATCID in MOD-028, MOD-029 and MOD-030. R2.1.1.1 - Replace phrase "operations studies and planning studies" with the phrase "planning of operations", to be consistent with the wording in MOD-001 R6. R2.1.2.1 - Replace phrase "operations studies and planning studies" with the phrase "planning of operations", to be consistent with the wording in MOD-001 R6. R3.4 - | Yes | | Yes | | |

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| | | | | | | | Bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on AFC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders. | | | | | |
| | Individual | Greg Ward / Darryl Curtis | Oncor Electric Delivery | | | | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). | Yes | | Yes | | This standard should not apply to ERCOT for the reason expressed in question 1. |
| | | | | | | | | | | | | BPA thanks the drafting team for clarifying that MOD-030 does not require the conversion of AFC to ATC and agrees with your assessment that there is no reliability need for such conversion. In addition, BPA respectfully submits the following observations and suggestions: a. There appears to be some conflicting overlap between R2.1.-R2.1.4.2. in MOD-030-1 and the System Operating Limits (SOL) Standards (FAC-010-1 and FAC-011-1). It is unclear to BPA that there is any reliability-based need for the identification of more Flowgates than are needed to protect SOLs. To that end, BPA suggests the following modifications to and renumbering of the above mentioned requirements: R2.1. Identify Flowgates used in the AFC process based, at a minimum, on the following criteria: R2.1.1. As necessary to protect established System Operating Limits (SOLs) or 2.1.1.1 Results of a first Contingency transfer analysis for ATC Paths internal to a |

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| | Group | | | Bonneville Power | Denise Koehn | Transmission Reliability Program | BPA does not believe any of the requirements are incorrect, though some are too prescriptive. See our response to question 4. | Yes | | Yes | | Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates. 2.1.1.1.1. Use first Contingency assumptions consistent with those first Contingencies used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems. 2.1.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate. 2.1.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology. 2.1.1.2.1. Use first Contingency assumptions consistent with those first Contingencies used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems. 2.1.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate. R2.1.2. Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology. R2.1.3. Any limiting Element/Contingency combination within the Transmission model that has been requested to be included |

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| | | | | | | | | | | | | by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where: 2.1.3.1. If the coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and - Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or - A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate. - The Transmission Operator may utilize distribution factors less than 5% if desired. 2.1.3.2. If the limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology. b. R2.4 has two bulletized sub-requirements that should either be numbered with a brief description provided as to how one would "respect the SOL" vs. simply setting the TFC equal to the SOL; or collapsed into R2.4 as follows: R2.4. Establish the TFC of each of the defined Flowgates as equal to: the System Operating Limit (SOL) of the Flowgate. c. The Time Horizons listed for all requirements should include the "Long-term Planning" Horizon, as ATC or AFC is to be calculated beyond the seasonal window. d. Balancing Authorities may be appropriately identified as Applicable Entities in this MOD and request that the Standards Drafting Team provide an explanation as to why they are not listed. |
| | Individual | Richard Kafka | Pepco Holdings, Inc | | | | PHI supports the comments of PJM and will not submit duplicate comments. | | | | | |
| | | | | | | | Requirement 1 Add to the end of R1 "provided that the data is not market sensitive." Requirement 2 R2.1 addresses criteria for identifying flowgates used in the AFC process. Certain operating conditions cause the use of | | | | | |

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| | Group | | | ISO RTO Council/Standards Review Committee (SRC) | Charles Yeung | Southwest Power Pool | temporary flowgates. Coordination tests may be executed between entities for a temporary flowgate which will be included in AFC calculations and congestion management systems. Would these situations require these temporary flowgates to remain in AFC processes even after the temporary conditions return to normal (transmission elements return to service)? In some cases, temporary flowgates created for short-term may not necessarily fall under the criteria established in R2.1 but should be allowed because of their immediate need in reliably operating the transmission system. R2.3 stipulates that: "At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested within thirty calendar days from the request." The requirement is unclear on how a Flowgate gets removed merely through a request if the criteria applied to R2 and its sub-requirements remain in effect to justify keeping the Flowgate in the AFC list. Further, who has the authority to make this request and on what basis the request can be granted? The standard is silent on these issues. This requirement is very loose which needs tightening up. Requirement 3 R3.2 and R3.3 - The update frequency for AFC calculations should be addressed by NAESB Business Practices. R3.4 – The last sentence in R3. 4 should be replaced with; "Equivalent representation of radial lines and facilities is allowed consistent with the Bulk Electric System definition." Requirement 5 R5.2 - R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD-001 and applied consistently across MODS 28, 29 and 30. Requirement 6 R6.3 - The IRC understands the SDT's reasons for using "Confirmed" reservations in accordance with the FERC regulations. Reservations that are in "Accepted", as well as, "Confirmed" status should be included. Once service is | Yes | The MOD standards assess the correct amount of reliability risk in areas that do not affect reliability. The IRC supports the position that no requirement from this set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but the IRC has a concern regarding the possibility of multiple violations resulting from a single event. The IRC requests that the potential for double counting of violations for a single event be eliminated. | |

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| | | | | | | | "Accepted" by a TSP it cannot be retracted. Using reservations that are in "Accepted" and "Confirmed" status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TSP from decrementing for accepted and confirmed TSRs. We understand that some TSPs maintain two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TSPs who maintain two sets of ATC values to post the "internal" ATC values to provide greater transparency and give customers a more accurate picture of capability available to new requests. Requirements 7 and 9 R7 and R9 Non-firm should be removed from this Reliability Standard and be considered NAESB scope. Requirement 10 The periodic requirements of R10 are NAESB scope. This requirement should be eliminated. | | preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. | | | |
| | | | | | | | | | | | We have the following comments on the VSLs: a. R1: The VSLs are proper for this requirement. However, the Measure needs to be fixed so that they correspond to the VSLs. Please see our comments on M1 under Q1. b. R2: We suggest the VSLs for R2 be rewritten, and where necessary, restructure R2 altogether to facilitate development of VSLs. For example, R2.1 is only one of the 6 subrequirements of R2, yet a condition that "The Transmission Operator did not include six or more Flowgates in their its AFC calculations that met the criteria described in R2.1." would put the TOP | |

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| | Individual | Ron Falsetti | Ontario IESO | | | | We have the following comments on the Requirements and Measures: a. R2.3 stipulates that: “At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested within thirty calendar days from the request.” The requirement is unclear on how a Flowgate gets removed merely through a request if the criteria applied to R2 and its sub-requirements remain in effect to justify keeping the Flowgate in the AFC list. Further, who has the authority to make this request and on what basis the request can be granted? The standard is silent on these issues. This requirement, to say the least, is very loose. b. R2.5 does not cover the situations when transmission configuration changes occur that results in a change to the SOL and hence the Flowgate TTC. c. The term “Transmission Service” in R4 is unclear. Does it mean transmission service reservations, or commitments? This needs to be clarified. d. The last bullet in R2.1.4.1 and the footnote to R6.2, R6.4, R7.2, R7.4 and R7.6 allow the use of threshold lower than 5%. This makes the 5% threshold stipulated in R2.1.1, R2.1.2 and R2.1.4 not enforceable. If lower threshold can be used, why stipulate a 5% in the first place? e. M1: This measure assesses compliance of R1.1; there is no | No | R2 should be assigned a Medium VRF since TFCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TFCs may result in the TSP over- | No | to a Severe violation despite the TOP might have met all the remaining 5 subrequirements. Another example is that the TOP is more than 9 month late in establishing the list of internal Flowgates but has otherwise met all the other subrequirements. Further, there are far too many single condition that would put a TOP to Severe violation despite it may have et all the other conditions, and there is no violation level assigned to failing R2.5.1, which is to update TFC when notified of a rating change. A major rewrite of this set of VSL in conjunction with restructuring R2 appears to be an appropriate course for the SDT. c. R3: Similar situation as in R2. R3 has 5 subrequirements and hence failing just one of them (except R3.1 for which VSLs are progressive (graded)) should not be assigned a Severe level. There needs to be consideration given to failing some combination of them for which Low, Moderate and High VSLs should be assigned. Unlike R2, R3 has a simpler structure and hence may not need to be restructured to facilitate proper assignments of VSLs. d. R5: This requirement has 3 subrequirements. It is generally expected that failing one of the 3 subrequirements would result in a | We commend the SDT for having worked very hard to try to meet FERC's earlier deadline, and for taking very positive steps responding to industry comments received from previous round of posting for comment and from the failed balloting process. However, owing to the number and size of the standards, there is a great potential for inconsistent treatment to the requirements, measures and VSLs among the standards. After reviewing all 6 standards and offering comments, we've found that there is quite a bit of inconsistency among the standards. For example, for a similar process, some requirements in a standard have only one level of subrequirements while in another standard there are two levels. In some standards that have requirements that contain subrequirements, there is only one measure while in another standard, similar process having similar requirement structure may have multiple measures. Still the vast majority of inconsistency is found in the VSLs: for similar requirement structure and content, some have appropriately graded VSLs while some have binary (none or Severe) VSLs; some have graded VSLs that is a function of the number of |

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| | | | | | | | measure for R1.2. f. M13 for R6: R6 stipulates the algorithm to establish AFCs. However, M13 provides the requirement for certain accuracy, which leads to the following questions: i. Is R6 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm? ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M13) to determine if the algorithm and its settings have been properly used. ii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure. g. M14 for R7: The same comment on M13 also applies here for R7. h. M18 for R11: Suggest to revised M18 to: “The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, it follows the procedure described in R11.” | | selling transmission services beyond the reliability bounds, risking the BES to unreliable operation | | Moderate VSL, 2 for a High VSL and all 3 for a Sever VSL as opposed to seeing only the graded VSL for failing R5.2. Furthermore, there may not be a large number of outages/retirements (for example 26-50) occurring during a modeling period within the total area that a TSP needs to model. Some VSLs for R5.2 may not be applicable for some TSPs even they may miss all the outages/retirements within the total area that it needs to model. Suggest the SDT revise this set of VSLs to take into account failing any combination of the 3 subrequirements, and the range of area size (and hence the total number of possible outages within a period) that a TSP needs to model. e. R6: For these VSLs to be appropriate, please see our comments and suggestion for changes on M13 under Q1. f. R7: For these VSLs to be appropriate, please see our comments and suggestion for changes on M14 under Q1. g. R8: The VSL has a condition that there is a violation if additional elements are used in the calculation of firm AFCs. Not allowing the use of additional elements is not stipulated in the requirement. Suggest to remove this condition from the VSL, or add this requirement to R8. h. R9: Same comment on R8 also applies here for calculating non-firm | subrequirements violated while others have VSLs that is determined by the extent of violation of any one of the subrequirements. The inconsistent wording among the requirements, their measures and VSLs is another area of concern. We realize the SDT is still working with a tight timeline. Nonetheless, we feel that the needed time must be spent to review the structure and quality of these standards to support measurability and the ability to develop proper VSLs. Unlike the development of VSLs for the approved standards – a process that did not allow for changing the requirements, the ATC SDT has the freedom to change the requirements as it sees necessary to facilitate proper development of measures and ease of VSL development thereby achieving a set of quality standards that are measurable and enforceable. We therefore suggest the SDT do spend some time to refine these standards to improve their quality rather than trying to post them in short order to get ahead on the timeline. |

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| | | | | | | | | | | | AFCs. i. R10: The VSLs as written indicates that failing any one of the 3 beyond some threshold levels would constitute a Severe violation. This is not consistent with the general principle that failing all subrequirements would result in a Severe violation. Suggest the SDT revise this set of VSLs to achieve consistency with the general principle. j. R11: Please see our comment on M18 under Q1. If the wording to M18 is revised as suggested, the wording for the VSL condition should be changed accordingly. | |
| | | | | | | | •In the Purpose field, why specify for short term use only? The Midwest ISO believes this methodology is valid for the planning horizon also. •R2 – In general, we believe this is not treated equally comparing to MOD-028 and MOD-029. There isn't a minimum criterion on what contingencies have to be included in MOD-028 or MOD-29. All they need to do is to include in their ATCID. Why can't flowgate methodology do the same thing? •R2.1.1/R2.1.2 – Below are a couple of comments related to these requirements. oR2.1.1.1/R2.1.2.1 – Overall, both requirements as written are unclear. The Midwest ISO questions what assumptions are referenced in these requirements and how would an auditor be able to verify that the TO is compliant. The Midwest ISO requests the requirement to either list specific assumptions or be deleted and leave it to FERC to address the issues on a case by case basis. oR2.1.1.2/R2.1.2.2 – The Midwest ISO requests that an example of the limiting element in series be provided. •R2.1.3 – The Midwest ISO believes that this requirement is too burdensome and stringent, and | | | | | |

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| Individual | John Harmon | The Midwest ISO | | | | sometimes will have no effect on a TO or TSP. If a TO chooses to model the topology for a TO or TSP far removed from its respective region, why is it mandated that all flowgates with TLR be honored. This requirement also gives no service for an instance where a TLR may occur due to a temporary condition such as a forced outage. This will greatly increase the number of flowgates that each TO will have to account for in their load flow calculations without much perceived benefit. •R2.2 – Edited the statement to read: "At a minimum, establish the list of Flowgates at least once per calendar year." The Midwest ISO believes that this would be a clearer requirement. •R2.3 – Edit the statement to read: "At a minimum, establish the list of external Flowgates that have been requested within thirty calendar days from the request." The Midwest ISO believes that this would be a clearer requirement. •R2.4 – The Midwest ISO believes that this requirement is identical to R12 in TOP-002. Since TOP-002 R12 will not be retired, R2.4 in MOD-030 is redundant and should be removed. However, if the DT does not agree, The Midwest ISO would then comment that for thermal limits, the thermal rating of the Flowgate should be used and not the SOL. •R4 – The Midwest ISO has two comments related to this requirement: oThe Midwest ISO has observed that a similar requirement is not in MOD-029. We feel that TSPs that follow the Rated System Path methodology should also be subjected to this requirement. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies. oThe sub-requirements (identified with a dash in the standard) seem to be written as though they are mutually exclusive. The Midwest ISO believes that a Source or Sink identified in a reservation that is discretely modeled can still be mapped to an "equivalence" or "aggregate" representation in the model. Background: For the Midwest ISO, although the internal Local Balancing Authorities are | Yes | | No | The tolerances included in the VSLs for R10 should be moved into the requirement itself. | The Midwest ISO believes that MOD-030 continues to be more stringent than MOD-028 and MOD-029. |

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| | | | | | | | discretely modeled, we would still like to map it to an “aggregate” – MISO – to be consistent with what is expected to be scheduled in real time. •R5.2 – Language should be added to say that this requirement applies if the data is supplied by the entities owning the information. •R6.2/R6.4/R6.6/R7.2/R7.4/R7.6 – The Midwest ISO has two comments related to these requirements: oLanguage should be added to state that the requirements are applicable only if the other TSPs provide necessary information. oThe Midwest ISO has observed that similar requirements are not in MOD-028 nor MOD-029. We feel that TSPs that use MOD-028 and MOD-029 should also be subjected to this requirement. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies. •R10 –First, the Midwest ISO believes that this requirement should be removed because there is no companion requirement in MOD-028 and MOD-029. Second, any forgiveness/tolerance for error should be included in the requirement instead of the VSL table because it is the requirement that determines whether the entities are in compliance, NOT the VSL table. Third, if this requirement has to stay, it should include similar outage/maintenance allowances for hourly values as in MOD-001. •R11 – The formula, as it is written, would result in using different flowgates to convert AFC to ATC and TFC to TTC. The Midwest ISO believes that we should use the same flowgate for both conversions. The formula should be used only for AFC-ATC conversion. TTC should be calculation by dividing TFC by DF for the same most ATC-limiting flowgate, •M11 – Revise the language to match revisions in R5.2 •M13&M14 – The Midwest ISO feels that both of these requirements are too burdensome for TSPs and ISOs/RTOs. The amount of data that would have to be retained for a 60 day period is too great. The Midwest ISO also questions the basis for a 60 day period and why these requirements were | | | | | |

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| | | | | | | | greatly expanded from their original wording. If the point of the requirement is to audit calculated values for compliance, how is the specific number of days of data relevant? The requirements from the previous version were appropriate. •M17 – Should reference calculating AFC not ATC. •Compliance 1.3 – The Midwest ISO questions the value in requiring that the list of Flowgates and their ratings be retained for 3 years when all other requirements are only 12 months? | | | | | |
| | | | | | | | R1.2 Add "definitions" to the requirement to read: "source and sink definitions". Similar to a comment provided for MOD-001, R2.1.1.1 and 2.1.2.1 use the term "operations studies and planning studies." Again, we believe that the intent is to tie reliability focused studies to the commercial ATC type studies. we think the inclusion of "reliability" with these terms helps to clarify the intent. Also, if the terms can be stadardized for both MOD-001 and MOD-030, then that would be optimum. MOD-028 and 029 do not specifically try to make this correlation and raises a question of why that is not done. R2.1.1 - needs rewording for clarification: From the results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability, as a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of 5% or less and within the Transmission Operator's system shall be included as Flowgates. R2.1.1.1 - The specific reference to SPS is misleading. There is nothing in the standards that preclude the use of SPSs, so being silent is better than pointing out just one technology. The use or non-use of SPSs could be presented in the assumptions/evidence documented per MOD-001 M Throughout - There are several references to the limiting element and contingency combinations. However, some flowgates are so sensitive to transfers that they need to be included for PTDF vs. OTDF. R2.1.4.1 & 2.1.4.2 - Delete "If" at the beginning of the | | | | | |

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| | Group | | | Entergy Services Inc. | Narinder K. Saini | Entergy Services Inc. | requirements statements. R2.1.2 - needs rewording for clarification. From the results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability, a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of 5% or less and within the Transmission Operator's system shall be included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology. 2.1.3 - How often does this update have to occur? R2.1.3 & 2.1.4 - Insert "Include" at the beginning of the requirements statements. R2.2 - Reword to "At a minimum create, modify, or delete the list of internal Flowgate definitions at least once per calendar year." R2.3 - Reword similar to R2.2. R5.2 Replace "during the period calculated" with "during the applicable period of the AFC calculation". R3.5 - the phrase "and beyond" seems very open-ended. For the very near timeframes where state estimator models are used, this is the biggest concern. We cannot model neighboring systems in great detail because they do not allow that use of their CEII since we post these cases on our OASIS site. R5.3 - The reference should be to R2.1.4 rather than R2.1.3 R6.3, 6.4, 6.5, and 6.6 - These requirements should not refer to only "all confirmed firm Point-to-Point Transmision Service expected to be scheduled". All confirmed firm Point-to-Point Transmission Service should be included for determining the impacts of ETC for firm commitments. The wording for R6.2 needs "based on:" added to the end to read like R6.1. R6.2 & 6.4 & 6.6 - Add a requirement that requires your neighbors to tell you about their NITS. If these requirements are going to stand, you need a way to ensure that you can get the appropriate data from neighbors in order to be compliant. The footnotes in R6.2, 6.4, 6.6, 7.2, 7.6, & 11 should be deleted with the | Yes | | Yes | | |

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| | | | | | | | suggested rewording of R2.1.1 and R2.1.2. R6.4 and 7.2 - how do you accomplish "filtered to reduce or eliminate duplicate impacts" especially as it relates to neighboring TSPs PTP reservations? The formula in R9 should be modified to replace ETCFi by a new term to reflect Firm commitments expected to be scheduled. TRMui definition should not use the term "Transmission Reliability Margin that has not been released (unreleased) for sale as TRM is not expected to be released. Only different values of TRM can be used for non firm ATC/AFC calculations different/lower than those used for firm. R10 - recalculation frequency in this requirement should be similar that included in MOD-001 R8. R10.1 - Entergy recommends to modify the language to "For Hourly, once per hour at least 99% of hours every calendar year." | | | | | |
| | | | | | | | | | | | | 1. The MRO continues to have issues with the overall approach on this standard in combination with the MOD-028. As previously indicated in prior comment periods, the MRO has Transmission Service Providers that manage the levels of transmission service to a reliable level with flowgates and then establishes border control area-to-control area flows to contract path levels so that contractual rights are not exceeded. The MRO reads the MOD-028 standard to require the application of the MOD-028 methodology for its control area-to-control area path postings while MOD-030 standard is used for the flowgate postings. The MRO understands from a discussion with a member of the SDT that in actuality the intent is that the MOD-030 would be used for flowgate calculations and that these quantities could be converted into the ATC path quantities for the control area to control area paths from border companies to outside the Transmission Service Providers area. This application of the flow gate methodology to possibly generate all postings in for a Transmission Service Provider including drive out is not clear from the standards |

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| | Group | | | MRO NERC Standards Review Subcommittee | Tom Mielnik | MidAmerican Energy Company (MEC) | 1. The MRO commends the SDT on revising R2.1.1 resulting in an improved description of contingency combinations to be included as flowgates. 2. The MRO commends the SDT on making numerous revisions to clarify that the standard provides the basis for AFC calculations not ATC. We believe that some additional changes in this regard are required. Under A. Introduction, 4. Applicability, 4.1.1 needs to be clarified by stating that the applicability of the standard is for "Each Transmission Operator that uses the Flowgate Methodology to support the calculation of AFCs on flowgates and when converting AFCs to ATCs." 4.1.2 needs to be clarified by stating that "Each Transmission Service Provider that uses The Flowgate Methodology to calculate AFCs on flowgates and when coverting AFCs to ATCs." 3. The MRO believes the words "all" should be deleted from R2.1.2, "any" from R2.1.3, three uses of "any" from R2.1.4, "all" from R5.2, "any" from R5.2, "all" from R6.1.2, two uses of "any" from R6.2, "all" from R6.2.2, "all" from R6.3, "any" and "all" from R6.4, "any" from R6.5, "any" and "alll" from R6.6, "all" from R7.1, "any" and "all" from R7.2, "any" from R7.3, "any" and "all" from R7.4, "any" and "all" from R7.6, "any" from R9. The MRO believes the use of these words are unnecessary and may lead to over-the-top auditing. We believe that the Measures, Compliance, and the VSLs should be changed to match these changes to the requirements. 4. R2.5.1 provides for only seven calendar days for updating the TFC once the Transmission Service Provider is notified of a change in a Rating. The MRO recommends that this be extended to 14 calendar days. 5. The MRO does not understand the need for R3.1 in requiring that generation Facility Ratings, such as generation maximum and mimum output levels must | Yes | The MRO commends the SDT on revising the VRFs to Lower. We believe the revised VRFs are in-line with the | Yes | | and should be clarified in MOD-030 and possibly MOD-028. 2. The MRO commends the SDT in making significant changes to this standard and reissuing it for comment. The MRO believes the eventual standard that is approved will serve the industry and customers better as a result. 3. The MRO acknowledges the consistant application of spelling out the full term followed by the abbreviation or acronym in brackets on the first time use. With the goal of consistancy across all the standards. 4. R6 and R7 – Overall, both requirements as written are unclear. The MRO asks that the standards drafting team specify what assumptions are referenced or else delete these requirements. The MRO notes that these requirements are covered by FERC order #890 anyway. 5. In the Purpose field, why specify for short term use only? The MRO believes this methodology is valid for the planning horizon also. 6. R2 – In general, we believe this is not treated equally comparing to MOD-028 and MOD-029. There isn't a minimum criterion on what contingencies have to be included in MOD-028 or MOD-29. All they need to do is to include in their ATCID. Why can't flowgate methodology do the same thing? 7. R2.1.3 – TheMRO believes that this requirement is too burdensome and stringent, and sometimes have no effect on a TO or TSP. If a TO chooses to model the topology for a TO or TSP far removed from its respective region, why is it mandated that all flowgates with TLR be honored. This requirement also gives no service for an instance where a TLR may occur due to a temporary condition such as a forced outage. This will greatly increase the number of flowgates that each TO will have to account for in their load flow calculations without much perceived benefit. 8. R2.2 – Edited the statement to read: At a minimum, establish the list of Flowgates at least once per calendar year. The MRO believes that this would be a clearer requirement. 9. R2.3 – Edit the statement to read: At a minimum, establish the list of |

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| | | | | | | | be included within the model. The MRO believes that there are instances where it would be inappropriate to base the AFC on the generation maximum or minimum output levels. Therefore, the MRO believes that this requirement should either be significantly revised to indicate what the SDT really means or else be deleted. 6. The MRO believes that the second sentence of R3.4 which specifies the extent to which equivalence is included in modeling be deleted. This seems to be micromanagement and could very well result in inappropriate models that result in worse AFCs. 7. The MRO urges the SDT to delete the new measures M13, M14, M15, and M16. We believe that these new measures are micromanagement of the Transmission Service Provider and encourage over-the-top auditing. The MRO considers these measures as written as being "deal-killers". 8. The MRO notices that MOD-028-1 provides in R6.3 provides for the use of "the lesser of the sum of incremental transfer capability and impacts of Firm Transmission Services" or the "sum of Facility Ratings of all ties comprising the ATC Path." It also provides in R6.4 for limiting TTC so that "TTC does not exceed that Transmission Operator's contractual rights." The MRO notes that similar provisions are missing from MOD-030-1. The MRO recommends that at a minimum, R11 provide that when flowgate AFCs are converted to ATCs that the ATCs have provisions for limiting ATCs to the sum of Facility Ratings of all ties comprising the ATC path and that such ATCs do not exceed Transmission Operator's contractual rights on the ATC path. | | NERC definitions of the VRF levels. | | | external Flowgates that have been requested within thirty calendar days from the request. The MRO believes that this would be a clearer requirement. 10. R2.4 – The MRO believes that this requirement is identical to R12 in TOP-002. Since TOP-002 R12 will not be retired, R2.4 in MOD-030 is redundant and should be removed. However, if the DT does not agree, The MRO would then comment that for thermal limits, the thermal rating of the Flowgate should be used and not the SOL. 11. R4 – The MRO has two comments related to this requirement: A. The MRO has observed that a similar requirement is not in MOD-029. We feel that TSPs that follow the Rated System Path methodology should also be subjected to this requirement. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies. B. The sub-requirements (identified with a dash in the standard) seem to be written as though they are mutually exclusive. The MRO believes that a Source or Sink identified in a reservation that is discretely modeled can still be mapped to an “equivalence” or “aggregate” representation in the model. 12. R5.2 – Language should be added to say that this requirement applies if the data is supplied by the entities owning the information. 13. R6.2/R6.4/R6.6/R7.2/R7.4/R7.6 – The MRO has two comments related to these requirements: A. Language should be added to state that the requirements are applicable only if the other TSPs provide necessary information. B. The MRO has observed that similar requirements are not in MOD-028 nor MOD-029. We feel that TSPs that use MOD-028 and MOD-029 should also be subjected to this requirement. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies. 14. R10 – First of all, All three methodologies should have the same calculation frequency and the same allowance for outages. The MRO believes that |

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| | | | | | | | | | | | | a load flow for hourly values shall be conducted at least once per day. Lowering the requirement for all to once per hour is overly burdensome.this requirement should be removed as there is no companion requirement in MOD-028 and MOD-029. Second, any forgiveness/tolerance for error should be included in the requirement instead of the VSL table because it is the requirement that determines whether the entities are in compliance, NOT the VSL table. Third, if this requirement has to stay, it should use similar outage/maintenance allowances for hourly values as in MOD-001. 15. R11 – The formula, as it is written, would result in using different flowgates to convert AFC to ATC and TFC to TTC. The MRO believes that we should use the same flowgate for both conversions. The formula should be used only for AFC-ATC conversion. TTC should be calculation by dividing TFC by DF for the same most ATC-limiting flowgate. 16. M17 – Should reference calculating AFC not ATC. |
| | Group | | | Southwest Power Pool | Kevin Bates | Southwest Power Pool | | Yes | | | | R2.1.3. Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months. R2.1 addresses criteria for identifying flowgates used in the AFC process. Certain operating conditions cause the use of temporary flowgates. Coordination tests may be executed between entities for a temporary flowgate which will be included in AFC calculations and congestion management systems. Would these situations require these temporary flowgates to remain in AFC processes even after the temporary conditions return to normal (transmission elements return to service)? In some cases, temporary flowgates created for short-term may not necessarily fall under the criteria established in R2.1 but should be allowed because of their immediate need in reliably operating the transmission system. |

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| | Individual | Jason Shaver | American Transmission Company | | | | 1. A.3 Clarify whether "for short term use" refers to the Operating Horizon, short term (1-5 yr) Planning Horizon, or both. 2. R2.1.2/M2 Delete the word "all" to avoid being overly inclusive. 3. R2.1.3 Delete the word "any" to "applicable" and change the term "Transmission model" to "Transmission Operator's area" to avoid being overly inclusive. 4. R2.1.4 Delete the words "any" to "applicable" and change the terms "Transmission model" to "Transmission Operator's area" to avoid being overly inclusive. 5. R2.4, R2.5, & R2.6/M5, M6, & M7 Remove these requirments and measures because the are redundant with R11 and R12 of TOP-002-2. If R2.5.1 is retained, then change the "seven calendar days" to "fourteen calendar days". 6.R3 Change "Transmission model" to "Transmission model of the Transmission Operator's area" 7. R3.4 Change "within its Reliability Coordinator's area" to "within the Transmission Operator's area". 8. R3.5 Change "beyond Reliability Coordinator's Areas" to "beyond the Transmission Operator's area". 9. R6.3 Need to include "Accepted" transmission service in the determination of Existing Transmission Commitments or clarify the reasoning for not including it (otherwise how are they accounted for?) M13, M14 For consistency, spell out "Transmission Service Provider". | Yes | | Yes | | The first time that each abbreviation or acronym is introduced, the full terminology should be stated followed by the abbreviation or acronym in brackets (i.e. TFC). Modification to Applicability Section: 4.1.1 Each Transmission Operator that uses the Flowgate Methodology 4.1.2 Each Transmission Service Provided that uses the Flowgate Methodology We believe that the remaining language ("to support the calculation of ATC for ATC Paths) can be deleted because of the subsequent changes to MOD-001-1. The SDT changes MOD-001-1 to accommodate both ATC and AFC. Please see our comments to MOD-001-1 that if implemented by the SDT should make the deletion acceptable. Proposed Effective Date: Please see our comments in MOD-001-1 about the proposed effective date. |
| | Individual | Rex McDaniel | Texas-New Mexico Power Company | | | | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). | Yes | | Yes | | This standard should not apply to ERCOT for the reason stated in Question 1. |

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| | | | | | | | | | | | | These comments are filed on behalf of City of Austin d/b/a Austin Energy to address proposed NERC 5 MOD Standards. Austin Energy is a municipally owned electric utility and a transmission service provider with the Electric Reliability Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with no explicit transmission services being sold. Current ERCOT market rules allow open transmission access to all loads and resources. ERCOT will continue to operate as a Single Balancing Authority under Nodal market design. Accordingly, as explained in more detail below, the NERC 5 MOD Standards should not be applied to ERCOT and transmission service providers within ERCOT under its current or proposed Nodal market design. Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. Applicable definitions: According to NERC Reliability Standards Glossary of Terms, Available Transfer Capability (ATC) is defined as: "A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability (TTC) less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows". TTC is defined as: the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions. CBM is defined as the amount of transmission transfer capability reserved by load |

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| | Group | | | Electric Service Delivery | Reza Ebrahimian | Austin Energy | | | | | | serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. TRM also is a component of ATC defined as: that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. Comments: ERCOT is an interconnection and a region with no synchronous AC ties with any other interconnections. In July 2001, based on a deregulated Retail and restructured Wholesale Markets, the ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT market is designed such that there are no explicit transmission services being sold, hence, Available Transfer Capability (ATC) is not a measure used in a commercial activity within the ERCOT market. The current ERCOT market rules allow open transmission access to all eligible loads and resources without considering any specific Transmission Service Provider (TSP). Transmission facilities ratings are based upon individual branch element designs and in cases of dynamic ratings, ambient conditions are also considered. ERCOT has several DC ties and an asynchronous tie using a Variable Frequency Transformer (VFT); however, the associated interchange capabilities are planned and coordinated by the TSPs involved. The current ERCOT Zonal Market uses a flow based congestion management methodology to predict potential congestions in the Day Ahead and Adjustment Periods. During the operating period, generation shift factors are used to determine the dispatch needed to remain within the constrained limits. The local congestions are managed using full AC load flow analysis and unit specific redispatch. MOD-001-1 is entirely about methodology and calculation of ATC, therefore, this standard is not applicable to ERCOT. MOD-008-1 covers Transmission Reliability Margin (TRM) methodology calculation. |

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| | | | | | | | | | | | | Mathematically, ATC is defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin (CBM). Therefore, TRM also is not applicable to ERCOT. MOD-028-1 covers Area Interchange calculation Methodology. Since ERCOT is a single control area, Area Interchange calculation is not applicable. MOD-029-1 covers Rated System Path Methodology, which is used to calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT. MOD-030-1 covers Flowgate methodology calculation of ATC, and therefore, is not applicable to ERCOT. ERCOT is currently transitioning to a Nodal Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a Security Constrained Economic Dispatch (SCED) approach to dispatch individual generating units and manage congestion. In the Nodal Market, ERCOT will still operate as a Single Balancing Authority. This again will not use ATC methodology, and aforementioned standards are not applicable to ERCOT in its ensuing Nodal Market. Therefore, Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. |
| | | | | | | | OTDF definition - capitalize "facilities" The Flowgate Methodology definition, like Area Interchange and Rated System Path, includes the text: "Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability." This text describes the derivation of ATC or AFC, and should not be part of a definition to differentiate between the AIM, RSP and Flowgate methods. R3.4 - I | | | | | |

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| | Individual | Allen Mosher | American Public Power Association | | | | support allowing "Equivalent representation of radial lines and facilities 161 kV or below" but equivalences for Elements included in the regional definition of the BES should be posted and explained in the TOP's and TSP's ATCID. R2.1.4.1, bullet #3 - This requirement states: "The Transmission Operator may utilize distribution factors less than 5% if desired." R6.2, R6.4, R6.6, R7.2, R7.4 and R7.6 and R11, definition of "P" each contain the following the following footnote: "A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized." MOD-28 AIM has similar language allowing use of alternative distribution factors, generally related to the use of differing local, subregional or regional TLR curtailment thresholds. Repetition of similar text in multiple requirements and identical footnotes indicates a single additional Requirement should be added to the Flowgate standard and Area Interchange standard. Alternatively, add the following sentence to R2.1.4.1 and to footnotes 1-7: "This lesser Distribution Factor shall be posted in the TSP's ATCID and coordinated with the applicable RC(s) and each adjacent TOP and TSP." R8 and R9 - Postbacks and counterflows: "Counterflows" should be a defined term. It is used in MOD-1, MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-28-1 R10, for example, reads: "counterflowsF are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID." This definition does not in any way describe what a counterflow is. "Postbacks" should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: "Postbacks[Firm] [Non-Firm] are changes to firm [non-firm] ATC [AFC] due to a change in the amount of Firm | Yes | | Yes | Yes - a major improvement | Great work - thanks to the SDT |

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| | | | | | | | [non-firm] Transmission Service reserved or scheduled for a period, as defined in Business Practices. Postbacks are generally a positive quantity." Also, include Postbacks in the "e.g." list of factors in M15 and M16. | | | | | |
| | Individual | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | | | | | | | | | Brazos Electric believes that the concept of the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for ATC Paths is not applicable to a single-control area operation like ERCOT. To address this issue, the Applicability section could have a clarifying statement that only TOPs or TSPs conducting area to area operations and hence have responsibility for ATC Path(s) are subject to the requirements of MOD-030 if it uses a Flowgate Methodology. |

**Consideration of Comments on Draft Standard — MOD-030 — Project 2006-07**

The ATC Standards Drafting Team thanks all commenters who submitted comments on the draft standard MOD-030-1 – Flowgate Methodology. This standard was posted for a 30-day public comment period from April 16, 2008 through May 15, 2008. The stakeholders were asked to provide feedback on the standard through a special electronic Standard Comment Form. There were more than 28 sets of comments, including comments from 93 different people from approximately 55 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

There were some comments that led the drafting team to modify language to improve clarity, but none of the changes made by the drafting team changed the scope or intent of the requirements in the standard.

**Applicability**

- Several entities have continued to express concern regarding the applicability of the ATC, TRM, and CBM standards. While the drafting team has attempted to write the standards in ways that are flexible and allow for organizational diversity, we note that FERC Order 890 makes reference to the use of Variances. Entities with non-traditional physical transmission markets or that have alternative ATC methodologies that meet or exceed the NERC ATC standards may wish to consider requesting one or more Variances related to these standards.

- Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

**Requirements**

- R2.1.3 - Some entities pointed out that as written, the requirement to include flowgates that have been in TLR would require the inclusion of flowgates that might be outside the scope of the transmission model if an entity chose to model beyond the requirements in the standard. The drafting team modified R2.1.3 to require only inclusion of those flowgates that have been subjected to an interconnection wide congestion management procedure AND meet the minimum model scope requirements of R3.4 and R3.5. Therefore even if the TO chooses to model a larger area, those flowgates that have been subjected to an interconnection wide congestion management procedure that are in that wider area not specified by R3.4 and R3.5 do not have to be included.
- R2.1.4.1 - Some entities questioned the concept of allowing entities to use distribution factor thresholds lower than those specified. The SDT clarified that as written the requirements makes inclusion below 5% optional, inclusion 5% or greater mandatory.
- R3.4 - Some entities questioned the use of the 161kV threshold, requesting either a lower threshold or a requirement to document reasons for using equivalences. The SDT suggested that if such requirements are desired, the commenter should submit a request for a regional standard.
- R6 and R7 - The concept of only considering service "expected to be scheduled" was questioned. The SDT explained that the intent was to allow for (but not require) entities to exclude reservations based on historical experience or knowledge, such as

seasonal use of reservation. If entities believe all reservations will be scheduled, then the entity may consider all reservations.

- R8 and R9 – Some entities pointed out that although MOD-001 discussed including details regarding the honoring of contractual allocations of capacity, MOD-030 was silent on the topic. The SDT has modified MOD-030 R8 and R9 to require the respecting contractual allocations of capacity.
- R10 - Some entities suggested that the allowance for 80 hours described in the MOD-001 ATC calculation schedule should apply to MOD-030's R10 as well. The SDT has modified MOD-030 R10 to allow for the annual allowance specified in MOD-001 R8.

**Measures**

- M13 and M14 - Some entities expressed concern with the measures associated with the ETC calculation. The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation of the whether an entity is compliant. In response to concerns with data retention, the SDT has modified the data retention and the measures. The data retention now states that data to demonstrate compliance with hourly ETC calculations must be retained for 14 days, for daily calculations must be retained for 30 days, and for monthly calculations must be retained for 60 days. The measure has been rephrased to clarify that the intent is to verify that the requirements for calculating ETC were used.

**Compliance**

- Most entities agree with the VRFs.
- One entity suggested that the VRF for R2 be raised. The majority of the team and the industry believes that a violation of R2 would not directly affect the electrical state or the capability of the bulk power system.
- Some commenter's expressed concern with potential for multiple violations of the standard due to a single event. The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.
- Some suggestions were made to change specific VSLs or measures. The SDT modified VSLs for R3 and R10, but did not modify the other measures or VSLs.

- The drafting team provided a summary of the use of time horizons to address some comments.

**Concepts**

- Some entities expressed concern that MOD-030 was more stringent than MOD-028 and MOD-029. The SDT explained that the methodologies were different, and therefore had different ways of documenting requirements, or different processes for meeting reliability goals, but in general, were consistent. A question was raised regarding whether the information required to be documented in each of the methodologies was consistent. The SDT reviewed this and confirmed that the requirements are equivalent across the methodologies.
- Several entities did not understand why MOD-001 and MOD-030 both had requirements related to recalculation frequency. The SDT explained that these two requirements are different, and address fundamental differences between the methodologies.
- Some entities suggested that the standard should not apply to non-firm ATC. The SDT stated that removal of non-firm from the standard could allow for unchecked selling of non-firm service, which could lead to concerns within real-time.
- Some entities suggested that the standard should define how AFC is calculated, but not that it should be calculated. The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives.
- The concept of "temporary" flowgates was raised, and whether or not the standard required temporary flowgates to be maintained indefinitely. The SDT stated that provided the conditions that cause the temporary flowgate to meet the criteria in R2.1 are no longer in existence, the flowgate could be removed immediately. Note that if the temporary flowgate had an interconnection-wide congestion management procedure invoked, the 12-month criteria would apply.
- Some entities questioned if the standard was in conflict with TOP-002 R12. The SDT believes that the MOD standards are the appropriate location for the reference to SOLs with regard to transfer capability. Additionally, TOP-002 R12 applies to the Transmission Service provider while R2.4 applies to the Transmission Operator. The drafting team believes that the TFC will be based on the most constrained facility's SOL (thermal, voltage, or stability based) for the monitored facilities considered in the flowgate, so no change is needed.
- One entity questioned the structure of the source/sink modeling requirements. The SDT explained the intent of the requirements, and provided examples of the manner in which various market models could be accommodated.
- Several entities identified a concern with requiring "all" or "any" data. The SDT clarified that providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC.
- Some entities suggested reducing the size of the modeling requirements. The SDT believes the current model size requirements are appropriate.
- Some entities expressed concern with the ability to share data without non-disclosure agreements in place. In general, the SDT expects that a Transmission Operator should already have appropriate agreements in place with its Transmission Service Provider to address this. If such contracts are not in place, the standard does not prohibit nor require them, but entities are still responsible for meeting the requirements in the standard.

- Some entities questioned whether the standard should be modified to address "accepted" reservations, in addition to confirmed reservations. The SDT responded that the standard does not prohibit the TSP from maintaining an "internal" ATC value for use in approving reservation requests that includes these Accepted reservation. This is the manner FERC has indicated to be an appropriate way for dealing with "Accepted" reservation in its regulations. To the extent ATC believes these numbers should be posted, the SDT believes ATC should develop a NAESB request for the posting of this information.
- Some entities did not understand the establishment of TFC for non-thermal limits. The SDT explained that, for example, the SOL limit could actually be a voltage limit, and this limit would have to be translated into a MW value to be assigned to a Flowgate in order to "respect the SOL".
- The concept of "filtering to reduce or eliminate duplicate impacts" was questioned. The SDT explained this can be accomplished by jointly developing an exclusion list with neighboring TSPs to identify duplicate reservations (i.e., reservations on both sides of an interface for one transaction).

**Implementation**

- Some entities expressed concern with the effective date and the "concurrent" implementation being dependent on "all" regulatory authorities. The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals.

**Variances**

The SDT believes it may be helpful to the industry to review the process for Variances. The Variance process can work either concurrent with or independent of the development of a standard. Because the drafting team working on a particular standard is likely to already have the necessary expertise to participate in the development of the Variance, concurrent development is generally more efficient. However, this may not always be practical; in this case, standards drafting may proceed, and even complete, prior to the development and approval of Variances. In this case, entities should seek to develop those Variances and seek their approval prior to the effective date of the standard. An entity is not exempt from meeting the requirements of the standard if the effective date has passed and that entity is in the process of developing a Variance.

The NERC process allows for three different types of variances:

- An Entity Variance
- A Regional Variance less than an Interconnection
- A Regional Variance on Interconnection-Wide basis

The NERC Rules of Procedure describe an Entity Variance as follows:

> Entity Variance — Any variance from a NERC reliability standard that is proposed to apply to one entity or a subset of entities within a limited portion of a regional entity, such as a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users, shall be approved through the regular standards development process defined in the NERC Reliability Standards Development Procedure and shall be made part of the applicable NERC reliability standard.

Entities seeking an Entity Variance should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requester is addressing the reliability goals of the standard. The ballot body is comprised of any member of the Registered Ballot Body that is interested and registers to join the ballot pool. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe a Regional Variance Less Than an Interconnection as follows:

> Any regional variance from a NERC reliability standard that is proposed to apply for a regional entity, but not for an interconnection, shall be approved through the NERC Reliability Standards Development Procedure, except that only members of the registered ballot body located in the affected interconnection shall be permitted to vote; and the variance shall be made part of the applicable NERC reliability standard.

Entities seeking a Regional Variance Less Than an Interconnection should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requestor is addressing the reliability goals of the standard. The ballot body is comprised of any interested entities that that have registered with NERC and is a user, owner, or operator of facilities located within the interconnection in which the region requesting the Variance is located. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe an Regional Variance on an Interconnection-wide Basis as follows:

> An interconnection-wide regional variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the NERC reliability standard. NERC shall rebuttably presume that a regional variance from a NERC reliability standard that is developed, in accordance with a procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Entities seeking a Regional Variance on an Interconnection-wide Basis should draft that Variance using the regional standards development process described in the region's delegation agreement. In that Variance, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Once approved through the regional standards development process, the Variance should be brought to NERC for filing with the appropriate regulatory authorities.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving these standards forward to posting for pre-ballot review.

In this “Consideration of Comments” document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standard can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

## Index to Questions, Comments, and Responses

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Thad Ness | AEP | x | | x | | x | x | | | | |
| 2. | Anita Lee (G3) | AESO | | x | | | | | | | | |
| 3. | Helen Stines (G1) | Alcoa Power Generating, Inc. | x | | x | | | | | | | |
| 4. | Ken Goldsmith (G5) | ALTW | | | | x | | | | | | |
| 5. | Eugene Warnecke (G1) | Ameren | x | | x | | | | | | | |
| 6. | Allen Mosher | American Public Power Association | x | | | x | | x | | | | |
| 7. | Jason Shaver | American Transmission Company | x | | | | | | | | | |
| 8. | Jerry Smith (G2) | APS | x | | | | | | | | | x |
| 9. | Dave Rudolph (G5) | Basin Electric | x | | x | | x | x | | | | |
| 10. | Chris Bradley (G1) | Big Rivers Electric Cooperative | x | | x | | | | | | | |
| 11. | Denise Koehn (G6) | Bonneville Power Administration | x | | x | | x | x | | | | |
| 12. | Mike Viles (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 13. | Abbey Nulph (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 14. | Don Watkins (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 15. | Patrick Roechelle (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 16. | Kammy Rogers-Holiday (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 17. | Robin Chung (G6) | Bonneville Power Administration | | | x | | x | x | | | | |
| 18. | Rebecca Berdahl (G6) | Bonneville Power Administration | | | x | | | | | | | |
| 19. | Susan Millar (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 20. | Todd Miller (G6) | Bonneville Power Administration | | | x | | x | x | | | | |
| 21. | Elizabeth Loebach (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 22. | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | x | | | | x | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 23. | Dave Lunceford (G2) | California ISO | | x | | | | | | | | x |
| 24. | Brent Kingsford (G3) | California ISO | | x | | | | | | | | |
| 25. | Frank Cumpton | California ISO | | x | | | | | | | | |
| 26. | Paul Rocha | CenterPoint Energy | x | | | | | | | | | |
| 27. | Don Reichenbach (G1) | Duke Energy - Carolinas | x | | x | | | | | | | |
| 28. | Greg Rowland | Duke Energy Corporation | x | | x | | x | x | | | | |
| 29. | Reza Ebrahimian | Electric Service Delivery | x | | | | | | | | | |
| 30. | Narinder K. Saini (G7) | Entergy Services, Inc. | x | | | | | | | | | |
| 31. | Joachim Francois (G1) | Entergy Services, Inc. | x | | x | | | | | | | |
| 32. | Ed Davis (G7) | Entergy Services, Inc | x | | | | | | | | | |
| 33. | George Bartlett (G7) | Entergy Services, Inc | x | | | | | | | | | |
| 34. | Lynna Estep (G7) | Entergy Services, Inc | x | | | | | | | | | |
| 35. | Michelle McNeece (G7) | Entergy Services, Inc | x | | | | | | | | | |
| 36. | Cameron Warren (G7) | Entergy Services, Inc | x | | | | | | | | | |
| 37. | Joachim Francois (G7) | Entergy Services, Inc | x | | | | | | | | | |
| 38. | Kham Vongkhamchanh (G7) | Entergy Services, Inc | x | | | | | | | | | |
| 39. | Jack Cashin/Barry Green | EPSA | | | | | x | x | | | | |
| 40. | H. Steven Myers (G3) (I) | ERCOT ISO | | x | | | | | | | | |
| 41. | Doug Hohlbaugh | FirstEnergy | x | | x | | x | x | | | | |
| 42. | Dave Folk | FirstEnergy | x | | x | | x | x | | | | |
| 43. | Rob Martinko | FirstEnergy | x | | x | | x | x | | | | |
| 44. | Sam Ciccone | FirstEnergy | x | | x | | x | x | | | | |
| 45. | Ross Kovacs (G1) | Georgia Transmission Corp. | x | | | | | | | | | |
| 46. | Joe Knight | GRE | x | | x | | x | x | | | | |
| 47. | David Kiguel (G4) | Hydro One Networks | x | | x | | | | | | | |
| 48. | Roger Champagne (G4) | Hydro Quebec TransEnergie | x | x | | | | | | | | |
| 49. | Ron Falsetti (G3) | IESO | | x | | | | | | | | |
| 50. | Matt Goldberg (G3) | ISO-New England | | x | | | | | | | | |
| 51. | Kathleen Goodman (G4) | ISO-New England | | x | | | | | | | | |
| 52. | Jim Useldinger | Kansas City Power & Light | x | | | | | | | | | |
| 53. | Eric Ruskamp (G5) | LES | x | | x | | x | x | | | | |
| 54. | Maria Neufeld | Manitoba Hydro | x | | x | | x | x | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 55. | Bill Phillips (G3) | MISO | | x | | | | | | | | |
| 56. | Terry Bilke (G5) | MISO | | x | | | | | | | | |
| 57. | John Harmon | MISO | | x | | | | | | | | |
| 58. | Carol Gerou (G5) | MP | x | | x | | x | x | | | | |
| 59. | Larry Brusseasu (G5) | MRO | | | | | | | | | | x |
| 60. | Michael Brytowski (G5) | MRO | | | | | | | | | | x |
| 61. | Tom Mielnik (G5) | MRO NERC Standards Review Subcommittee | x | | x | | x | x | | | | |
| 62. | Jerry Tang (G1) | Municipal Electric Auth. of GA | x | | x | | | | | | | |
| 63. | Joe DePoorter (G5) | MGE | | | x | x | x | x | | | | |
| 64. | Randy Macdonald | New Brunswick System Operator | | x | | | | | | | | |
| 65. | Jim Castle (G3) | New York ISO | | s | | | | | | | | |
| 66. | Greg Campoli (G4) | New York ISO | | x | | | | | | | | |
| 67. | Alan Adamson (G4) | NYSRC | | | | | | | | | | |
| 68. | Rick White (G4) | Northeast Utilities | x | | | x | | | | | | |
| 69. | Guy V. Zito (G4) | NPCC | | | | | | | | | | x |
| 70. | Greg Ward / Darryl Curtis | Oncor Electric Delivery | x | | | | | | | | | |
| 71. | Ron Falsetti | Ontario IESO | | x | | | | | | | | |
| 72. | Richard Kafka | Pepco Holdings, Inc. | x | | x | | x | x | | | | |
| 73. | Patrick Brown (G3) (I) | PJM | | x | | | | | | | | |
| 74. | Phil Creech (G1) | Progress Energy - Carolinas | x | | x | | | | | | | |
| 75. | Phil Riley | Public Service Commission of South Carolina | | | | | | | | | x | |
| 76. | W. Shannon Black (G2) | Sacramento Municipal Utility District | | | x | | | | | | | |
| 77. | Pat Huntley (G1) | SERC | | | | | | | | | | x |
| 78. | John Troha (G1) | SERC | | | | | | | | | | x |
| 79. | Vicky Budreau (G1) | So. Carolina Public Service Auth. | x | | x | | | | | | | |
| 80. | Al McMeekin (G1) | South Carolina Electric & Gas | x | | x | | | | | | | |
| 81. | Stan Shealy (G1) | South Carolina Electric & Gas | x | | x | | | | | | | |
| 82. | Jim Griffith (G1) | Southern Co. | x | | x | | | | | | | |
| 83. | DuShaune Carter (G1) | Southern Co. | x | | x | | | | | | | |
| 84. | Kevin Bates | Southwest Power Pool | | x | | | | | | | | |
| 85. | Charles Yeung (G3) | Southwest Power Pool | | x | | | | | | | | |
| 86. | Chuck Falls (G2) | SRP | x | | | | | | | | | x |
| 87. | Doug Bailey | SERC Available Transfer Capability Working Group | x | | x | | | | | | x | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 88. | Rex McDaniel | Texas-New Mexico Power Company | x | | | | | | | | | |
| 89. | Brian Evans Mongeon G4) | Utilitiy Services, LLC | | | | | | x | | | | |
| 90. | Jim Haigh (G5) | WAPA | x | | | | | x | | | | |
| 91. | Neal Balu | WPS | | | x | x | x | x | | | | |
| 92. | Pam Oreschnick | Xcel Energy | x | | x | | x | x | | | | |

I — Individual
G1 — SERC Available Transfer Capability Working Group
G2 — WECC Market Interface Committee / Sub Commtt / ATC Task Force
G3 — ISO RTO Council/Standards Review Committee (SRC)
G4 — NPCC Regional Standards Committee
G5 — MRO Standards Review Committee
G6 — Bonneville Power
G7 — Entergy

1. **The drafting team modified some requirements and associated measures in MOD-030 to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct. Incorrect Requirement(s) or Measure(s):**

**Summary Consideration:**

Some entities requested that either the Transmission Operator or the Transmission Service Provider be applicable. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity “or” another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.

Several entities expressed concern with ERCOT’s applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

Some entities expressed concern that MOD-030 was more stringent than MOD-028 and MOD-029. The SDT explained that the methodologies were different, and therefore had different ways of documenting requirements, or different processes for meeting reliability goals, but in general, were consistent. A question was raised regarding whether the information required to be documented in each of the methodologies was consistent. The SDT reviewed this and confirmed that the requirements are equivalent across the methodologies.

Several entities did not understand why MOD-001 and MOD-030 both had requirements related to recalculation frequency. The SDT explained that these two requirements are different, and address fundamental differences between the methodologies.

Some entities suggested that the standard should not apply to non-firm ATC. The SDT stated that removal of non-firm from the standard could allow for unchecked selling of non-firm service, which could lead to concerns within real-time.

Some entities suggested that the standard should define how AFC is calculated, but not that it should be calculated. The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives.

Some entities questioned the use of the 161kV threshold, requesting either a lower threshold or a requirement to document reasons for using equivalences. The SDT suggested that if such requirements are desired, the commenter should submit a request for a regional standard.

The concept of “temporary” flowgates was raised, and whether or not the standard required temporary flowgates to be maintained indefinitely. The SDT stated that provided the conditions that cause the temporary flowgate to meet the criteria in R2.1 are no longer in existence, the flowgate could be removed immediately. Note that if the temporary flowgate had an interconnection-wide congestion management procedure invoked, the 12-month criteria would apply.

Some entities questioned the concept of allowing entities to use distribution factor thresholds lower than those specified. The SDT clarified that as written the requirements makes inclusion below 5% optional, inclusion 5% or greater mandatory.

Some entities expressed concern with the measures associated with the ETC calculation. The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation of the whether an entity is compliant. In response to concerns with data retention, the SDT has modified the data retention and the measure. The data retention now states that data to demonstrate compliance with hourly ETC calculations must be retained for 14 days, for daily calculations must be retained for 30 days, and for monthly calculations must be retained for 60 days. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used.

Some entities pointed out that as written, the requirement to include flowgates that have been in TLR would require the inclusion of flowgates that might be outside the scope of the transmission model if an entity chose to model beyond the requirements in the standard. The drafting team modified R2.1.3 to require only inclusion of those flowgates that have been subjected to an interconnection wide congestion management procedure AND meet the minimum model scope requirements of R3.4 and R3.5. Therefore even if the TO chooses to model a larger area, those flowgates that have been subjected to an interconnection wide congestion management procedure that are in that wider area not specified by R3.4 and R3.5 do not have to be included.

Some entities questioned if the standard was in conflict with TOP-002 R12. The SDT believes that the MOD standards are the appropriate location for the reference to SOLs with regard to transfer capability. Additionally, TOP-002 R12 applies to the Transmission Service provider while R2.4 applies to the Transmission Operator. The drafting team believes that the TFC will be based on the most constrained facility's SOL (thermal, voltage, or stability based) for the monitored facilities considered in the flowgate, so no change is needed.

One entity questioned the structure of the source/sink modeling requirements. The SDT explained the intent of the requirements, and provided examples of the manner in which various market models could be accommodated.

The concept of only considering service "expected to be scheduled" was questioned. The SDT explained that the intent was to allow for (but not require) entities to exclude reservations based on historical experience or knowledge, such as seasonal use of reservation. If entities believe all reservations will be scheduled, then the entity may consider all reservations.

The concept of "filtering to reduce or eliminate duplicate impacts" was questioned. The SDT explained this can be accomplished by jointly developing an exclusion list with neighboring TSPs to identify duplicate reservations (i.e., reservations on both sides of an interface for one transaction).

Some entities suggested that the allowance for 80 hours described in the MOD-001 ATC calculation schedule should apply to MOD-030's R10 as well. The SDT has modified MOD-030 R10 to allow for the annual allowance specified in MOD-001 R8.

Several entities identified a concern with requiring "all" or "any" data. The SDT clarified that providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC.

Some entities pointed out that although MOD-001 discussed including details regarding the honoring of contractual allocations of capacity, MOD-030 was silent on the topic. The SDT has modified MOD-030 R8 and R9 to require the respecting contractual allocations of capacity.

Some entities suggested reducing the size of the modeling requirements. The SDT believes the current model size requirements are appropriate.

| **Organization/Group** | **Question 1 - Incorrect Requirement(s) or Measure(s):** |
|---|---|
| WECC Market Interface Committee / Sub Commtt ATC Task Force | MOD-30, M13 and M14 as drafted require the TSP to be "capable" of demonstration but do not require actual demonstration. The WECC Team suggests a minor rewrite to state, "The TSP shall demonstrate that..." This shifts the measurement from the TSP's mere capability to an actual performance. |
| **Response:** The drafting team has made this change. | |
| WECC Market Interface Committee ATC Task Force | MOD-30, M13 and M14 as drafted require the TSP to be "capable" of demonstration but do not require actual demonstration. The WECC Team suggests a minor rewrite to state, "The TSP shall demonstrate that..." This shifts the measurement from the TSP's mere capability to an actual performance. |
| **Response:** The drafting team has made this change. | |
| EPSA | Through this revision process, some of the MOD standards have included an explicit requirement for consistency between planning assumptions and modeling assumptions used in calculation of ATC. In particular, requirement 6.1 of the previous version of MOD 030 included such a requirement and we believe it should be retained. |
| **Response:** This requirement is located in MOD-001 which applies to all MOD-028, MOD-029 and MOD-030. | |
| ERCOT ISO | Requirement 1:I suggest modifying the requirement to state: "The Transmission Service Provider with ATC Path(s) shall include in its ?Available Transfer Capability Implementation Document? (ATCID).<br><br>Requirement 2:I suggest modifying the requirement to state: "The Transmission Operator with ATC Path(s) shall perform the following:<br><br>Requirement 3:I suggest modifying the requirement to state: "The Transmission Operator with ATC Path(s) shall make available to the Transmission Service Provider with ATC Path(s) a Transmission model to determine |

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| | Available Flowgate Capability (AFC) that meets the following criteria:<br><br>Requirement 4:I suggest modifying the requirement to state: "When calculating AFCs, the Transmission Service Provider with ATC Path(s) shall represent the impact of Transmission Service as follows:<br><br>Requirement 5:I suggest modifying the requirement to state: "When calculating AFCs, the Transmission Service Provider with ATC Path(s) shall:<br><br>Requirement 6:I suggest modifying the requirement to state: "When calculating the impact of ETC for firm commitments (ETCFi) for all time periods for a Flowgate, the Transmission Service Provider with ATC Path(s) shall sum the following:<br><br>Requirement 7:I suggest modifying the requirement to state: "When calculating the impact of ETC for non-firm commitments (ETCNFi) for all time periods for a Flowgate the Transmission Service Provider with ATC Path(s) shall sum:<br><br>Requirement 8:I suggest modifying the requirement to state: "When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:<br><br>Requirement 9:I suggest modifying the requirement to state: "When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:<br><br>Requirement 10:I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall recalculate AFC, utilizing the updated models described in R3.3, R3.4, and R5, at a minimum on the following frequency:<br><br>Requirement 11:I suggest modifying the requirement to state: "When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider with ATC Path(s) shall convert those values based on the following algorithm:" |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Flowgate methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard. | |

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| Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. *(Loc. Cit.)* | |
| Oncor Electric Delivery | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Flowgate methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. *(Loc. Cit.)* | |
| Texas-New Mexico Power Company | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Flowgate methodology. To the extent ERCOT does | |

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| not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| Kansas City Power & Light | The Transmission Service Provider should be added along with the TOP for these functions in all requirements. |
| Response: Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. | |
| FirstEnergy | Requirement 2, Applicable Entity: FE believes that this requirement and its associated sub-requirements are incorrectly assigned to the Transmission Operator. In reviewing the presently approved Functional Model (FM) Version 3 and its associated Technical Document, the determination of total transfer capability clearly falls to a planning function. In FM Version 3, task 3c of the Function — Planning Reliability states "Review and determine total transfer capability (generally one year and beyond) as appropriate." This is the only area that explicitly states "determine" as it relates to total transfer capability. The FM Version 3 later describes the responsibilities of the Planning Coordinators and Transmission Planners as having a role in coordinating total transfer capability. Nowhere within the Functional Model is this assignment relegated to the real-time aspect of the Transmission Operator. Additionally, since R2.5 allows the responsible entity to establish Total Flowgate Capabilities once per year, it would seem reasonable that this would be applicable to a planning function. FirstEnergy believes the appropriate responsible entity is the Planning Coordinator or Transmission Planner since this entity would likely have the same wide-area view that is covered by the corresponding Transmission Service Provider who is determining the Available Flowgate Capability. Assigning the determination of total transfer capability to the Planning Coordinator would also better align the standard for implementation within the RTO construct as well as non-market areas. The tasks described within R2 are completed by FE's RTO organizations — MISO and PJM — for the transmission facilities owned and operated by FirstEnergy. The standard should not be written in a way that would knowingly require some sort of delegation assignment for a large portion of the transmission system.<br>**Response:** R2 specifies how flowgates should be chosen for inclusion in AFC calculations and how their ratings |

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| | should be determined, not the actual AFC calculation. The drafting team believes the Transmission Operator is the appropriate entity for this task because they are responsible for keeping the system within its operating limits. Furthermore since this standard is applicable to a wide array of business models it would not be possible to avoid all possibility of delegation agreements.<br><br>R2 - MOD-030 does not appear to be consistent with MOD-028 and MOD-029 with respect to the criterion on which contingencies must be analyzed to determine Total Transfer Capability. In MOD-030 R2 is very prescriptive on how TFC is determined with regard to the contingencies that must be analyzed and the distribution factor thresholds that lead to a flowgate definition. However, MOD-028 and MOD-029 simply require the ATCID to describe the "how". For example, in MOD-028 R1.4 states that the ATCID include "A description of the manner in which Contingencies are identified for use in the TTC [Total Transfer Capability] process." FE suggess changes are needed to R2 to align with the MOD-028 and MOD-029 standards.<br>**Response:** MOD-028 and MOD-029 do not limit the subset of limiting elements and contingencies that are considered in ATC calculations; MOD-030, on the other hand, bases the calculation of AFC on a limited subset of limiting elements and contingencies; therefore R2 of MOD-030 must contain criteria for selecting this subset of flowgates.<br><br>R2.4 – The first bullet of R2.4 should state that when a TFC is based on a thermal rating that it reflects the lowest facility rating for the monitored facility(ies) considered in the flowgate. The reference to the SOL should be reserved to only the second bullet which would appropriately account for a voltage or stability limit.<br>**Response:** The drafting team believes that the TFC will be based on the most constrained facility's SOL (thermal, voltage, or stability based) for the monitored facilities considered in the flowgate, so no change is needed.<br><br>R10 – As stated in FE's MOD-001 comments, it is suggested that the requirements for frequency of recalculating ATC be dealt with in MOD-001 (R8) to ensure a consistent application across MOD-028, MOD-029 and MOD-030 that presently does not exist. If MOD-001 R8 is revised as suggested, R10 in MOD-030 can be deleted.<br>**Response:** These two requirements are different, and address fundamental differences between the methodologies. MOD-001 discusses the recalculation of ATC on a fixed schedule unless the components in the ATC equation change. MOD-030 R10 addresses calculation of AFC on a schedule consistent with the MOD-001 requirement. However, there is additional information in the MOD-030 requirement that is specific to that methodology. MOD-030 R10 does not require full recalculation of the distribution factors through an update of the transmission model; updates of the transmission model occur on a separate schedule as defined in MOD- |

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| | 030 R3. MOD-028 addresses this similarly through the recalculation of TTC on a separate schedule as defined in MOD-028 R5. MOD-029 addresses changes to topology through adjustments to TTC. Because of these technical differences between the methodologies, the SDT believes having the two requirements is appropriate. |
| **Response:** Please see in-line responses. | |
| PJM | Requirement 1? Add to the end of R1 ?provided that the data is not market sensitive.<br>**Response:** R1 does not require inclusion of data in the ATCID, only methodology information, so this caveat is not necessary.<br><br>“Requirement 2” R2.1.3 – The interconnection wide congestion management procedures should be listed for each Interconnection. For the Eastern Interconnection this is the TLR process.<br>**Response:** The titles of these procedures are listed in other standards and do not need to be repeated here. If the title changes in the other standard it may make this standard inconsistent.<br><br>Requirement 3? R3.2 and R3.3 -The update frequency for AFC calculations should be addressed by NAESB Business Practices.<br>**Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives.<br><br>R3.4 – The last sentence in R3. 4 should be replaced with; “Equivalent representation of radial lines and facilities is allowed consistent with the Bulk Electric System standards.”<br>**Response:** The drafting team does believe the suggested language is effective without the development of regional standards to support it. The Drafting Team notes that the language of R2.1 allows detailed modeling of 161 kV and below; the language does not require it.<br><br>Requirement 5? R5.2 – R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD-001 and applied consistently across MODS 28, 29 and 30.<br>**Response:** MOD-001 R3.6 does not specify which calculations the outages have to be used in - it requests clarification of outage processing rules for outages that are in effect for partial days or months. We have clarified MOD-001 to make this more easily understood. MOD-030 R5.2 requires that the outages be included as described in the ATCID – it does not specify hourly. |

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| | Requirement 6? R6.3 - PJM understands the SDT's reasons for using "Confirmed" reservations in accordance with the FERC regulations. Reservations that are in "Accepted", as well as, "Confirmed" status should be included. Once service is "Accepted" by a TP it cannot be retracted. Using reservations that are in "Accepted" and "Confirmed" status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TP from decrementing for accepted and confirmed TSRs. We understand that some TPs maintain two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TPs who maintain two sets of ATC values to post the "internal" ATC values to provide greater transparency and give customers a more accurate picture of capability available to new requests.<br>**Response:** The standard does not prohibit the TSP from maintaining an "internal" ATC value for use in approving reservation requests that includes these Accepted reservations. To the extent the PJM believes these numbers should be posted, the SDT believes the IRC should develop a NAESB request for the posting of this information.<br><br>Requirements 7 and 9 – R7 and R9 Non-firm should be removed from this Reliability Standard and be considered NAESB scope.<br>**Response:** Removal of non-firm from the standard could allow for unchecked selling of non-firm service, which could lead to concerns within real-time.<br><br>Requirement 10? The periodic requirements of R10 are NAESB scope. This requirement should be eliminated.<br>**Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives. |
| **Response:** Please see in line responses. | |
| Pepco Holdings, Inc | PHI supports the comments of PJM and will not submit duplicate comments. |
| **Response:** See response to PJM comments. | |
| Duke Energy Corporation | R1 – Need to ensure that comparable information should be required in either the study report or the ATCID in MOD-028, MOD-029 and MOD-030.<br>**Response:** The MOD-028 and MOD-030 standards have requirements for information to be located in the ATCID. MOD-029 has requirements for the comparable information to be included in the resulting study report. The SDT has reviewed and confirmed that the requirements are equivalent across the methodologies.<br><br>R2.1.1.1 – Replace phrase "operations studies and planning studies" with the phrase "planning of operations" to |

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| | be consistent with the wording in MOD-001 R6.<br>**Response:** The SDT has made this change as suggested.<br><br>R2.1.2.1 – Replace phrase "operations studies and planning studies? with the phrase ?planning of operations?, to be consistent with the wording in MOD-001 R6.<br>**Response:** The SDT has made this change as suggested.<br><br>R3.4 - Bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on AFC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders.<br><br>**Response:** The Drafting Team notes that the language of R2.1 allows detailed modeling of 161 kV and below; the language does not require it. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. Requirements for Data Exchange in MOD-001 already address sharing of models to support reliability objectives; to the extent a reliability entity has concerns regarding the use of equivalences within the model, the SDT encourages those entities to work directly with each other. Disclosure of this information to Transmission Customers should be addressed through the use of the NAESB process. |
| **Response:** Please see in-line response. | |
| ISO RTO Council/Standards Review Committee (SRC) | Requirement 1 – Add to the end of R1 "provided that the data is not market sensitive. "<br>**Response:** R1 does not require inclusion of data in the ATCID, only methodology information, so this caveat is not necessary.<br><br>Requirement 2R2.1 addresses criteria for identifying flowgates used in the AFC process. Certain operating conditions cause the use of temporary flowgates. Coordination tests may be executed between entities for a temporary flowgate which will be included in AFC calculations and congestion management systems. Would these situations require these temporary flowgates to remain in AFC processes even after the temporary conditions return to normal (transmission elements return to service)?<br>Response: No, there is no minimum duration for which a flowgate must be considered. Provided the conditions that cause the temporary flowgate to meet the criteria in R2.1 are no longer in existence, the flowgate could be removed immediately. Note that if the temporary flowgate had a interconnection-wide congestion management procedure invoked, the 12-month criteria would apply. |

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| | In some cases, temporary flowgates created for short-term may not necessarily fall under the criteria established in R2.1 but should be allowed because of their immediate need in reliably operating the transmission system.<br>**Response:** The minimum criteria specified in R2.1 do not preclude the use of additional flowgates.<br><br>R2.3 stipulates that: “At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested within thirty calendar days from the request.” The requirement is unclear on how a Flowgate gets removed merely through a request if the criteria applied to R2 and its sub-requirements remain in effect to justify keeping the Flowgate in the AFC list. Further, who has the authority to make this request and on what basis the request can be granted? The standard is silent on these issues. This requirement is very loose which needs tightening up.<br>**Response:** R2.3 has been clarified to specify that the requests are those referenced in R2.1.4 (by other Transmission Service Providers).<br><br>Requirement 3R3.2 and R3.3 -The update frequency for AFC calculations should be addressed by NAESB Business Practices.R3.4 – The last sentence in R3. 4 should be replaced with; “Equivalent representation of radial lines and facilities is allowed consistent with the Bulk Electric System definition.” Requirement 5R5.2 - R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD-001 and applied consistently across MODS 28, 29 and 30.Requirement 6R6.3 - The IRC understands the SDT’s reasons for using “Confirmed” reservations in accordance with the FERC regulations. Reservations that are in “Accepted”, as well as, “Confirmed” status should be included. Once service is “Accepted” by a TSP it cannot be retracted. Using reservations that are in “Accepted” and “Confirmed” status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TSP from decrementing for accepted and confirmed TSRs. We understand that some TSPs maintain two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TSPs who maintain two sets of ATC values to post the “internal” ATC values to provide greater transparency and give customers a more accurate picture of capability available to new requests. Requirements 7 and 9 R7 and R9 Non-firm should be removed from this Reliability Standard and be considered NAESB scope. Requirement 10The periodic requirements of R10 are NAESB scope. This requirement should be eliminated.<br>**Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives. |

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| **Response:** Please see in-line responses. | |
| Ontario IESO | We have the following comments on the Requirements and Measures: a. R2.3 stipulates that: ?At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested within thirty calendar days from the request.? The requirement is unclear on how a Flowgate gets removed merely through a request if the criteria applied to R2 and its sub-requirements remain in effect to justify keeping the Flowgate in the AFC list. Further, who has the authority to make this request and on what basis the request can be granted? The standard is silent on these issues. This requirement, to say the least, is very loose.<br>**Response:** R2.3 has been clarified to specify that the requests are those referenced in R2.1.4 (by other Transmission Service Providers).<br><br>b. R2.5 does not cover the situations when transmission configuration changes occur that results in a change to the SOL and hence the Flowgate TTC.<br>**Response:** R2.5 does not prevent changing the TFC more frequently than once per year and R2.5.1 specifies that it should be changed if the TFC changes. (The drafting team assumes the commenter meant Flowgate TFC).<br><br>c. The term "Transmission Service" in R4 is unclear. Does it mean transmission service reservations, or commitments? This needs to be clarified.<br>**Response:** The sub-bullet in R4 specifies that this is referring to reservations.<br><br>d. The last bullet in R2.1.4.1 and the footnote to R6.2, R6.4, R7.2, R7.4 and R7.6 allow the use of threshold lower than 5%. This makes the 5% threshold stipulated in R2.1.1, R2.1.2 and R2.1.4 not enforceable. If lower threshold can be used, why stipulate a 5% in the first place?<br>**Response:** As written the requirement makes inclusion below 5% optional, inclusion 5% or greater mandatory.<br><br>e. M1: This measure assesses compliance of R1.1; there is no measure for R1.2.<br>**Response:** The phrase, "and information on how sources and sinks are accounted for" was added to M1.<br><br>f. M13 for R6: R6 stipulates the algorithm to establish AFCs. However, M13 provides the requirement for certain accuracy, which leads to the following questions:<br>i. Is R6 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm? |

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| | ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M13) to determine if the algorithm and its settings have been properly used. ii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure. g. M14 for R7: The same comment on M13 also applies here for R7.<br>**Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation of the whether an entity is compliant. In response to concerns with data retention, the SDT has modified the data retention and the measure. The data retention now states that data to demonstrate compliance with hourly ETC calculations must be retained for 14 days, for daily calculations must be retained for 30 days, and for monthly calculations must be retained for 60 days. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used.<br>h. M18 for R11: Suggest to revised M18 to: "The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, it follows the procedure described in R11."<br>**Response:** The drafting team has made this change as suggested. |
| **Response:** Please see in-line responses. | |
| The Midwest ISO | In the Purpose field, why specify for short term use only? The Midwest ISO believes this methodology is valid for the planning horizon also.<br>**Response:** ATC is only required to be calculated for 13 months so it was not thought appropriate to mandate that this standard be used beyond that. However, it also does not preclude using this method in the planning horizon. |

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| | R2 – In general, we believe this is not treated equally comparing to MOD-028 and MOD-029. There isn't a minimum criterion on what contingencies have to be included in MOD-028 or MOD-29. All they need to do is to include in their ATCID. Why can't flowgate methodology do the same thing?<br>**Response:** MOD-028 and MOD-029 do not limit the subset of limiting elements and contingencies that are considered in ATC calculations; MOD-030, on the other hand, bases the calculation of AFC on a limited subset of limiting elements and contingencies, therefore R2 of MOD-030 must contain criteria for selecting this subset of flowgates.<br><br>R2.1.1/R2.1.2. Below are a couple of comments related to these requirements. or 2.1.1.1/R2.1.2.1? Overall, both requirements as written are unclear. The Midwest ISO questions what assumptions are referenced in these requirements and how would an auditor be able to verify that the TO is compliant. The Midwest ISO requests the requirement to either list specific assumptions or be deleted and leave it to FERC to address the issues on a case by case basis.<br>**Response:** This requirement was designed to address consistency of AFC calculation and operational and planning studies. The drafting team believes this is the best place to address this. Because there is not a one-to-one correlation between TTC and TFC calculation R6 in MOD-001 does not fully address the consistency in this methodology. The drafting team has modified the requirement to reference "criteria" rather than assumptions to clarify that the explicit list of contingencies doesn't have to match, but the criteria for selecting contingencies does. For example, test all 230kV within a certain zone would be a criteria, as opposed to a listing of all the facilities tested.<br><br>oR2.1.1.2/R2.1.2.2 – The Midwest ISO requests that an example of the limiting element in series be provided.<br>**Response:** The drafting team believes that an example is not necessary in the standard as this is a commonly understood concept. The drafting team is referring to a series circuit made up of transmission facilities. For example, a 230kV line that comes into what is effectively a load distribution station that also has an additional 230kV line.<br><br>R2.1.3 – The Midwest ISO believes that this requirement is too burdensome and stringent, and sometimes will have no effect on a TO or TSP. If a TO chooses to model the topology for a TO or TSP far removed from its respective region, why is it mandated that all flowgates with TLR be honored. This requirement also gives no service for an instance where a TLR may occur due to a temporary condition such as a forced outage. This will greatly increase the number of flowgates that each TO will have to account for in their load flow calculations without much perceived benefit. |

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| | **Response:** The drafting team has modified R2.1.3 to require only inclusion of those flowgates that have been subjected to an interconnection wide congestion management procedure AND meet the minimum model scope requirements of R3.4 and R3.5, therefore even if the TO chooses to model a larger area, those flowgates that have been subjected to an interconnection wide congestion management procedure that are in that wider area not specified by R3.4 and R3.5 do not have to be included.<br><br>R2.2 – Edited the statement to read: "At a minimum, establish the list of Flowgates at least once per calendar year." The Midwest ISO believes that this would be a clearer requirement.<br>R2.3 – Edit the statement to read: "At a minimum, establish the list of external Flowgates that have been requested within thirty calendar days from the request." The Midwest ISO believes that this would be a clearer requirement.<br>**Response:** The drafting team believes that "to create, modify or delete" appropriately adds to the clarity of these requirements.<br><br>R2.4 – The Midwest ISO believes that this requirement is identical to R12 in TOP-002. Since TOP-002 R12 will not be retired, R2.4 in MOD-030 is redundant and should be removed. However, if the DT does not agree, The Midwest ISO would then comment that for thermal limits, the thermal rating of the Flowgate should be used and not the SOL.<br>**Response:** The SDT believes that the MOD standards are the appropriate location for the reference to SOLs with regard to transfer capability. Additionally, TOP-002 R12 applies to the Transmission Service provider while R2.4 applies to the Transmission Operator. The drafting team believes that the TFC will be based on the most constrained facility's SOL (thermal, voltage, or stability based) for the monitored facilities considered in the flowgate, so no change is needed.<br><br>R4 – The Midwest ISO has two comments related to this requirement: o The Midwest ISO has observed that a similar requirement is not in MOD-029. We feel that TSPs that follow the Rated System Path methodology should also be subjected to this requirement. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies.<br>**Response:** R4 specifies how transmission service reservations shall be modeled. The Rated System Path method does not use simulation to analyze reservations, so a similar requirement would not make sense in MOD-029.<br><br>O The sub-requirements (identified with a dash in the standard) seem to be written as though they are mutually |

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| | exclusive. The Midwest ISO believes that a Source or Sink identified in a reservation that is discretely modeled can still be mapped to an "equivalence" or "aggregate" representation in the model. Background: For the Midwest ISO, although the internal Local Balancing Authorities are discretely modeled, we would still like to map it to an "aggregate" – MISO – to be consistent with what is expected to be scheduled in real time.<br>**Response:** They are mutually exclusive. However, the SDT believes that the scenario you describe is not problematic. In cases where MISO is modeling imports, we expect that the reservation would have a source outside MISO and a sink of MISO. This would be acceptable, as "MISO" would be discretely modeled as a system. In cases where MISO is modeling imports, we expect that the reservation would have a source of MISO and a sink outside MISO. This would also be acceptable. For internal transactions, we would expect that a source of MISO and a sink of MISO would be invalid from a modeling perspective, and effectively result in zero flow (a transfer distribution factor of zero). To the extent MISO wanted to model internal BA to BA flows, it could utilize the POR and POD, provided this convention was described in the ATCID. In some cases where entities use the source and sink fields for financial purposes, the SDT is aware that other entities use the POR or POD to address this as well, which is acceptable provided it has been so defined in their ATCID pursuant to R1.2.<br><br>R5.2 – Language should be added to say that this requirement applies if the data is supplied by the entities owning the information.<br><br>R6.2/R6.4/R6.6/R7.2/R7.4/R7.6 ? The Midwest ISO has two comments related to these requirements: o Language should be added to state that the requirements are applicable only if the other TSPs provide necessary information.<br>**Response:** The standard is requiring that entities request this information of their neighboring entities. To the extent entities do not provide it, the other entities would be out of compliance with R9 of MOD-001.<br><br>O The Midwest ISO has observed that similar requirements are not in MOD-028 nor MOD-029. We feel that TSPs that use MOD-028 and MOD-029 should also be subjected to this requirement. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies.<br>**Response:** Assuming that the comment refers to the previous requirements of R6.2, R6.4, R6.6, R7.2, R7.4, and R7.6, the SDT notes that similar language is found in MOD-028 R3, R8, and R9, and in MOD-029 R1, R5 and R6. The SDT notes that the unique nature of Flowgates (having to refer to the impact of a reservation, rather than the nominal value itself) can lead to much more verbose requirements. Additionally, many of the analyses of third-party impacts undertaken in the Flowgate methodology to determine AFC are also undertaken in the other methodologies – but as part of the determination of TTC. |

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| | R10 – First, the Midwest ISO believes that this requirement should be removed because there is no companion requirement in MOD-028 and MOD-029. Second, any forgiveness/tolerance for error should be included in the requirement instead of the VSL table because it is the requirement that determines whether the entities are in compliance, NOT the VSL table. Third, if this requirement has to stay, it should include similar outage/maintenance allowances for hourly values as in MOD-001.<br>**Response:** These two requirements are different, and address fundamental differences between the methodologies. MOD-001 discusses the recalculation of ATC on a fixed schedule unless the components in the ATC equation change. MOD-030 R10 addresses calculation of AFC on a schedule consistent with the MOD-001 requirement. However, there is additional information in the MOD-030 requirement that is specific to that methodology. MOD-030 R10 does not require full recalculation of the distribution factors through an update of the transmission model; updates of the transmission model occur on a separate schedule as defined in MOD-030 R3. MOD-028 addresses this similarly through the recalculation of TTC on a separate schedule as defined in MOD-028 R5. MOD-029 addresses changes to topology through adjustments to TTC. Because of these technical differences between the methodologies, the SDT believes having the two requirements is appropriate.<br><br>The SDT has modified MOD-030 R10 to allow for the annual allowance specified in R8.<br><br>R11 – The formula, as it is written, would result in using different flowgates to convert AFC to ATC and TFC to TTC. The Midwest ISO believes that we should use the same flowgate for both conversions. The formula should be used only for AFC-ATC conversion. TTC should be calculation by dividing TFC by DF for the same most ATC-limiting flowgate,<br>**Response: T**he current formula is a valid approach for calculating TTC. Implementing as suggested would result in the TTC changing every time the most limiting flowgate changed.<br><br>M11 – Revise the language to match revisions in R5.2 –<br>**Response:** The SDT has not made revisions to R5.2 that require changes to M11.<br><br>M13&M14 – The Midwest ISO feels that both of these requirements are too burdensome for TSPs and ISOs/RTOs. The amount of data that would have to be retained for a 60 day period is too great. The Midwest ISO also questions the basis for a 60 day period and why these requirements were greatly expanded from their original wording. If the point of the requirement is to audit calculated values for compliance, how is the specific number of days of data relevant? The requirements from the previous version were appropriate. |

<table>
<tr><th>Organization/Group</th><th>Question 1 - Incorrect Requirement(s) or Measure(s):</th></tr>
<tr><td></td><td>Response: The drafting team developed this measure so that a benchmark could be developed to verify that an entity’s processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a “pass/fail” VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity’s process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how “repeatable” the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation of the whether an entity is compliant. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used.<br><br>In response to concerns with data retention, the SDT has modified the data retention and the measure. The data retention now states that data to demonstrate compliance with hourly ETC calculations must be retained for 14 days, for daily calculations must be retained for 30 days, and for monthly calculations must be retained for 60 days. Entities are already required to retain data for longer than 60 days in order to meet OASIS regulations. As such, the SDT does not believe this to be an onerous requirement.<br><br>M17 – Should reference calculating AFC not ATC.<br>Response: This change has been made.<br><br>Compliance 1.3 – The Midwest ISO questions the value in requiring that the list of Flowgates and their ratings be retained for 3 years when all other requirements are only 12 months?<br>Response: 3 years is the default value for compliance data retention – there was not a strong argument for these particular requirements to deviate from the default.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
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| Entergy Services Inc. | R1.2 Add "definitions" to the requirement to read: "source and sink definitions".<br>**Response:** The drafting team does not believe adding the word "definitions" is appropriate. The requirement is to define how the source and sink in a reservation is accounted for in the AFC process. The definitions of sources and sinks is required in R1.2.3.<br><br>Similar to a comment provided for MOD-001, R2.1.1.1 and 2.1.2.1 use the term "operations studies and planning studies." Again, we believe that the intent is to tie reliability focused studies to the commercial ATC type studies. we think the inclusion of "reliability" with these terms helps to clarify the intent. Also, if the terms can be standardized for both MOD-001 and MOD-030, then that would be optimum.<br>**Response:** The requirements have been modified to remove the word "studies" to ensure consistency with MOD-001 R6, so "reliability" is no longer needed.<br><br>MOD-028 and 029 do not specifically try to make this correlation and raises a question of why that is not done.<br>**Response:** R6 in MOD-001 fully addresses the issue of consistency for the Area Interchange and Rated System Path methodologies but since there is not a one-to-one correlation between TTC and TFC calculation R6 in MOD-001 does not fully address the consistency in this methodology.<br><br>R2.1.1 – needs rewording for clarification: From the results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability, as a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of 5% or less and within the Transmission Operator's system shall be included as Flowgates.<br>**Response:** The drafting team does not believe the suggested rewording adds any clarification.<br><br>R2.1.1.1 - The specific reference to SPS is misleading. There is nothing in the standards that preclude the use of SPSs, so being silent is better than pointing out just one technology. The use or non-use of SPSs could be presented in the assumptions/evidence documented per MOD-001 M.<br>**Response:** The SDT added the SPS language based on comments received during the ballot process.<br><br>Throughout – There are several references to the limiting element and contingency combinations. However, some flowgates are so sensitive to transfers that they need to be included for PTDF vs. OTDF.<br>**Response:** The drafting team reviewed the standard and determined that PTDF and OTDF have been used appropriately. |

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| | R2.1.4.1 & 2.1.4.2 - Delete "If" at the beginning of the requirements statements.<br>**Response:** The SDT has made the change as suggested.<br><br>R2.1.2 – needs rewording for clarification. From the results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability, a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of 5% or less and within the Transmission Operator's system shall be included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.<br>**Response:** The drafting team does not believe the suggested rewording adds any clarification.<br><br>2.1.3 - How often does this update have to occur?<br>**Response:** R2.2 requires that the list of flowgates to be established at a minimum once per year and this includes those flowgates specified in R2.1.3<br><br>R2.1.3 & 2.1.4 - Insert "Include" at the beginning of the requirements statements.<br>**Response:** The word "identify" in R2.1 has been changed to "include".<br><br>R2.2 - Reword to "At a minimum create, modify, or delete the list of internal Flowgate definitions at least once per calendar year."<br>R2.3 - Reword similar to R2.2.<br>**Response:** The drafting team has reviewed this and did not believe the rewording improves the requirement.<br><br>R5.2 Replace "during the period calculated" with "during the applicable period of the AFC calculation".<br>**Response:** The SDT has made the change as suggested.<br><br>R3.5 - the phrase "and beyond" seems very open-ended. For the very near timeframes where state estimator models are used, this is the biggest concern. We cannot model neighboring systems in great detail because they do not allow that use of their CEII since we post these cases on our OASIS site.<br>**Response:** R3.5 does not require modeling details in areas beyond your own – it allows equivalent representation which does not need to include CEII. |

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| | R5.3 - The reference should be to R2.1.4 rather than R2.1.3<br>**Response:** The SDT has made the change as suggested.<br><br>R6.3, 6.4, 6.5, and 6.6 - These requirements should not refer to only "all confirmed firm Point-to-Point Transmission Service expected to be scheduled". All confirmed firm Point-to-Point Transmission Service should be included for determining the impacts of ETC for firm commitments.<br>**Response:** The requirement does not prevent inclusion of all confirmed firm Point-to-Point Transmission Service. However, there are situations where inclusion of *all* would not be appropriate, such as when confirmed reservations exist that have impacts in opposing directions and only one would be expected to be scheduled at certain times while the other would be expected to be scheduled at other times.<br><br>The wording for R6.2 needs "based on:" added to the end to read like R6.1.<br>**Response:** The SDT has made the change as suggested.<br><br>R6.2 & 6.4 & 6.6 - Add a requirement that requires your neighbors to tell you about their NITS. If these requirements are going to stand, you need a way to ensure that you can get the appropriate data from neighbors in order to be compliant.<br>**Response:** This is contained in R9 of MOD-001.<br><br>The footnotes in R6.2, 6.4, 6.6, 7.2, 7.6, & 11 should be deleted with the suggested rewording of R2.1.1 and R2.1.2.<br>**Response:** Since R2.1.1 and R2.1.2 were not reworded, the footnotes should not be deleted.<br><br>R6.4 and 7.2 - how do you accomplish "filtered to reduce or eliminate duplicate impacts" especially as it relates to neighboring TSPs PTP reservations?<br>**Response:** This can be accomplished by jointly developing an exclusion list with neighboring TSPs to identify duplicate reservations (i.e., reservations on both sides of an interface for one transaction).<br><br>The formula in R9 should be modified to replace ETCFi by a new term to reflect Firm commitments expected to be scheduled.<br>**Response:** The unscheduled confirmed firm point to point transmission service will be accounted for through |

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| | the Postback term, so this change does not need to be made.<br><br>TRMui definition should not use the term "Transmission Reliability Margin that has not been released (unreleased) for sale as TRM is not expected to be released. Only different values of TRM can be used for non firm ATC/AFC calculations different/lower than those used for firm.<br>**Response:** The concept is the same – this is a phrasing difference only and would not change the substance of the requirement.<br><br>R10 - recalculation frequency in this requirement should be similar that included in MOD-001 R8.<br><br>R10.1 - Entergy recommends to modify the language to "For Hourly, once per hour at least 99% of hours every calendar year."<br>**Response:** The SDT has modified MOD-030 R10 to allow for the annual allowance specified in MOD-001 R8. |
| **Response:** | |
| MRO NERC Standards Review Subcommittee | 1. The MRO commends the SDT on revising R2.1.1 resulting in an improved description of contingency combinations to be included as flowgates.<br>**Response:** Thank you for your supportive comment.<br><br>2. The MRO commends the SDT on making numerous revisions to clarify that the standard provides the basis for AFC calculations not ATC. We believe that some additional changes in this regard are required. Under A. Introduction, 4. Applicability, 4.1.1 needs to be clarified by stating that the applicability of the standard is for "Each Transmission Operator that uses the Flowgate Methodology to support the calculation of AFCs on flowgates and when converting AFCs to ATCs." 4.1.2 need to be clarified by stating that "Each Transmission Service Provider that uses The Flowgate Methodology to calculate AFCs on flowgates and when converting AFCs to ATCs."<br>**Response:** The drafting team has modified the applicability to reference AFCs instead of ATCs.<br><br>3. The MRO believes the words "all" should be deleted from R2.1.2, "any" from R2.1.3, three uses of "any" from R2.1.4, "all" from R5.2, "any" from R5.2, "all" from R6.1.2, two uses of "any" from R6.2, "all" from R6.2.2, "all" from R6.3, "any" and "all" from R6.4, "any" from R6.5, "any" and "all" from R6.6, "all" from R7.1, "any" and "all" from R7.2, "any" from R7.3, "any" and "all" from R7.4, "any" and "all" from R7.6, "any" from R9. The MRO believes the use of these words are unnecessary and may lead to over-the-top auditing. We believe that the |

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| | Measures, Compliance, and the VSLs should be changed to match these changes to the requirements.<br>**Response:** Providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of "any" and "all" prevents discretionary sets of data being provided and argued as being compliant.<br><br>4. R2.5.1 provides for only seven calendar days for updating the TFC once the Transmission Service Provider is notified of a change in a Rating. The MRO recommends that this be extended to 14 calendar days.<br>**Response:** 7 days is consistent with the duration allowed in MOD028 for providing TTC data and MOD-029 for providing the results of the TTC Study Report.<br><br>5. The MRO does not understand the need for R3.1 in requiring that generation Facility Ratings, such as generation maximum and minimum output levels must be included within the model. The MRO believes that there are instances where it would be inappropriate to base the AFC on the generation maximum or minimum output levels. Therefore, the MRO believes that this requirement should either be significantly revised to indicate what the SDT really means or else be deleted.<br>**Response:** The drafting team does not agree that there are instances where it would be inappropriate to base the AFC on these output levels because AFC should be based on the most realistic modeling possible.<br><br>6. The MRO believes that the second sentence of R3.4 which specifies the extent to which equivalence is included in modeling be deleted. This seems to be micromanagement and could very well result in inappropriate models that result in worse AFCs.<br>**Response:** If this sentence is removed then equivalencing would not be allowed at all – a fully detailed model would have to be used. The Drafting Team has included a fixed minimum of what cannot be equivalence to ensure too much equivalencing is not applied. The Drafting Team notes that the language allows detailed modeling of 161 kV and below; the language does not require it. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent .<br><br>7. The MRO urges the SDT to delete the new measures M13, M14, M15, and M16. We believe that these new measures are micromanagement of the Transmission Service Provider and encourage over-the-top auditing. The MRO considers these measures as written as being "deal-killers".<br>**Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the |

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| | previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation of the whether an entity is compliant. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used.<br><br>In response to concerns with data retention, the SDT has modified the data retention and the measure. The data retention now states that data to demonstrate compliance with hourly ETC calculations must be retained for 14 days, for daily calculations must be retained for 30 days, and for monthly calculations must be retained for 60 days. Entities are already required to retain data for longer than 60 days in order to meet OASIS regulations. As such, the SDT does not believe this to be an onerous requirement.<br><br>8. The MRO notices that MOD-028-1 provides in R6.3 provides for the use of "the lesser of the sum of incremental transfer capability and impacts of Firm Transmission Services" or the "sum of Facility Ratings of all ties comprising the ATC Path." It also provides in R6.4 for limiting TTC so that "TTC does not exceed that Transmission Operator's contractual rights." The MRO notes that similar provisions are missing from MOD-030-1. The MRO recommends that at a minimum, R11 provide that when flowgate AFCs are converted to ATCs that the ATCs have provisions for limiting ATCs to the sum of Facility Ratings of all ties comprising the ATC path and that such ATCs do not exceed Transmission Operator's contractual rights on the ATC path.<br>**Response:** The SDT has modified MOD-030 R8 and R9 to require the respecting contractual allocations of capacity. |
| American Transmission Company | 1. A.3 Clarify whether "for short term use" refers to the Operating Horizon, short term (1-5 yr) Planning Horizon, or both.<br>**Response:** The parent standard, MOD-001, clearly requires ATC calculations out as far as 13 months; this timeframe is consistent with the current version of the MOD standards and has not been modified in this drafting |

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| | process. Since the 'horizon' terms are used differently throughout the industry the Drafting Team does not want to incorporate those specific terms.<br><br>2. R2.1.2/M2 Delete the word "all" to avoid being overly inclusive.<br><br>3. R2.1.3 Delete the word "any" to "applicable" and change the term "Transmission model" to "Transmission Operator's area" to avoid being overly inclusive.<br><br>4. R2.1.4 Delete the words "any" to "applicable" and change the terms "Transmission model" to "Transmission Operator's area" to avoid being overly inclusive.<br>**Response:** Removing these words would not change the substance of the requirements, therefore no change was made. Providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of "any" and "all" prevents discretionary sets of data being provided and argued as being compliant.<br><br>5. R2.4, R2.5, & R2.6/M5, M6, & M7 – Remove these requirements and measures because they are redundant with R11 and R12 of TOP-002-2.<br>**Response:** The SDT believes that the MOD standards are the appropriate location for the reference to SOLs with regard to transfer capability. Additionally, TOP-002 R12 applies to the Transmission Service provider while R2.4 applies to the Transmission Operator.<br><br>If R2.5.1 is retained, then change the "seven calendar days" to "fourteen calendar days".<br>**Response:** 7 days is consistent with the duration allowed in MOD028 for providing TTC data and MOD-029 for providing the results of the TTC Study Report.<br><br>6.R3 Change "Transmission model" to "Transmission model of the Transmission Operator's area"<br>7. R3.4 Change "within its Reliability Coordinator's area" to "within the Transmission Operator's area".<br>8. R3.5 Change "beyond Reliability Coordinator's Areas" to "beyond the Transmission Operator's area".<br>**Response:** A model larger than that of the Transmission Operator's area is required to ensure the accuracy of the calculations.<br><br>9. R6.3 Need to include "Accepted" transmission service in the determination of Existing Transmission |

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| | Commitments or clarify the reasoning for not including it (otherwise how are they accounted for?)<br>**Response:** The standard does not prohibit the TSP from maintaining an "internal" ATC value for use in approving reservation requests that includes these Accepted reservation. This is the manner FERC has indicated to be an appropriate way for dealing with "Accepted" reservation in its regulations. To the extent ATC believes these numbers should be posted, the SDT believes ATC should develop a NAESB request for the posting of this information.<br><br>M13, M14 For consistency, spell out "Transmission Service Provider".<br>**Response:** The SDT has made this change as suggested. |
| **Response:** Please see in-line responses. | |
| American Public Power Association | OTDF definition - capitalize "facilities"<br>**Response:** This change has been made in both the OTDF and PTDF definitions, and in all other places in the standard where it was not capitalized.<br><br>The Flowgate Methodology definition, like Area Interchange and Rated System Path, includes the text: "Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability." This text describes the derivation of ATC or AFC, and should not be part of a definition to differentiate between the AIM, RSP and Flowgate methods.<br>**Response:** The derivation of AFC is part of the Area Interchange Methodology, it is not identical in all three methods and it is appropriate to be included.<br><br>R3.4 - I support allowing "Equivalent representation of radial lines and facilities 161 kV or below? but equivalences for Elements included in the regional definition of the BES should be posted and explained in the TOP's and TSP's ATCID.<br>**Response:** The Drafting Team notes that the language of R3.4 allows detailed modeling of 161 kV and below; the language does not require it. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. Requirements for Data Exchange in MOD-001 already address sharing of models to support reliability objectives; to the extent a reliability entity has concerns regarding the use of equivalences within the model, the SDT encourages those entities to work directly with each other. Disclosure of this information to Transmission Customers should be addressed through the use of the NAESB process. |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | R2.1.4.1, bullet #3 - This requirement states: – The Transmission Operator may utilize distribution factors less than 5% if desired? R6.2, R6.4, R6.6, R7.2, R7.4 and R7.6 and R11, definition of “P” each contain the following the following footnote: "A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized." MOD-28 AIM has similar language allowing use of alternative distribution factors, generally related to the use of differing local, subregional or regional TLR curtailment thresholds. Repetition of similar text in multiple requirements and identical footnotes indicates a single additional Requirement should be added to the Flowgate standard and Area Interchange standard.<br>**Response:** This language is not a requirement, it is clarification of the requirement; therefore it would not be appropriate to add a requirement attempting to avoid the repetition.<br><br>Alternatively, add the following sentence to R2.1.4.1 and to footnotes 1-7: This lesser Distribution Factor shall be posted in the TSP’s ATCID and coordinated with the applicable RC(s) and each adjacent TOP and TSP.?<br>**Response:** The SDT believes that the MOD-001 R 3.1 requirement would already require the TSP to document this information in the ATCID.<br><br>R8 and R9 – Postbacks and counterflows: Counterflows should be a defined term. It is used in MOD-1, MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-28-1 R10, for example, reads: “counterflows” are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.? This definition does not in any way describe what a counterflow is.<br>“Postbacks” should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: Postbacks [Firm] [Non-Firm] are changes to firm [non-firm] ATC [AFC] due to a change in the amount of Firm [non-firm] Transmission Service reserved or scheduled for a period, as defined in Business Practices. Postbacks are generally a positive quantity.<br>**Response:** The SDT has reviewed the standards, and finds that the Postbacks and counterflows definitions, the requirements for the ATCID, and the requirements and measures for calculating ATC in the methodologies address this sufficiently. MOD-001 indicates in the definition that Postbacks are defined by business practices, while the individual methodology standards indicate that Postbacks are “changes to firm (non-firm) ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.” Counterflows is an industry term, and the manner in which it applies to these standards is described in the methodologies (“adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID”), as well as in MOD-001 R3.2 |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| | Also, include Postbacks in the "e.g." list of factors in M15 and M16.<br>**Response:** The example list in M15 and M16 is merely an example and not necessarily all inclusive. |
| **Response:** Please see in-line responses. | |
| Bonneville Power | BPA does not believe any of the requirements are incorrect, though some are too prescriptive. See our response to question 4. |
| **Response:** See response in question 4. | |
| NPCC Regional Standards Committee | None |

**2. The drafting team has modified the Violation Risk Factors for MOD-030 to reflect industry concerns that they did not match NERC's VRF definitions. NERC's VRF definitions are listed below. Are the current VRFs established correctly? If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.**

High Risk Requirement:

(a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement:

(a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement: is administrative in nature and

(a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or

(b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.?

**Summary Consideration:**

Most entities agree with the VRFs.

One entity suggested that the VRF for R2 be raised. The majority of the team and the industry believes that a violation of R2 would not directly affect the electrical state or the capability of the bulk power system.

| Organization/Group | Question 2: | Question 2 Comments: |
|---|---|---|
| Ontario IESO | No | R2 should be assigned a Medium VRF since TFCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TFCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable |

| Organization/Group | Question 2: | Question 2 Comments: |
|---|---|---|
| | | operation |
| **Response:** The Drafting Team disagrees.  The majority of the team and the industry believes that a violation of R2 would not directly affect the electrical state or the capability of the bulk power system. | | |
| MRO NERC Standards Review Subcommittee | Yes | The MRO commends the SDT on revising the VRFs to Lower.  We believe the revised VRFs are in-line with the NERC definitions of the VRF levels. |
| **Response:** Thank you for your supportive comment. | | |
| FirstEnergy | Yes | FE supports the SDT's adjustment of VRFs such that no VRF within the ATC standards exceeds a "Lower" rating.  We concur with the team's reasoning and rationale provided in response to ballot comments in making this change. |
| **Response:** Thank you for your supportive comment. | | |
| PJM | Yes | PJM supports NERC?s position to revise all Violation Risk Factors to have an assigned risk factor of ?Lower.? A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. |
| **Response:** Thank you for your supportive comment. | | |
| ISO RTO Council/Standards Review Committee (SRC) | Yes | The MOD standards assess the correct amount of reliability risk in areas that do not affect reliability. The IRC supports the position that no requirement from this set of ATC standards should have an assigned Risk Factor exceeding “lower”.  A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. |
| **Response:** Thank you for your supportive comment. | | |
| SERC ATCWG | Yes | |
| WECC Market Interface Committee / Sub Commtt? ATC Task Force | Yes | |

| Organization/Group | Question 2: | Question 2 Comments: |
|---|---|---|
| Kansas City Power & Light | Yes | |
| WECC Market Interface Committee ATC Task Force | Yes | |
| Manitoba Hydro | Yes | |
| NPCC Regional Standards Committee | Yes | |
| Public Service Commission of South Carolina | Yes | |
| Duke Energy Corporation | Yes | |
| Oncor Electric Delivery | Yes | |
| Bonneville Power | Yes | |
| The Midwest ISO | Yes | |
| Entergy Services Inc. | Yes | |
| Southwest Power Pool | Yes | |
| American Transmission Company | Yes | |
| Texas-New Mexico Power Company | Yes | |
| EPSA | | No comment |

**3. The drafting team has modified the Violation Severity Levels for MOD-030 to reflect industry concerns that they were too "pass/fail" oriented. Are the current VSLs established correctly? If "No," please identify specific VSLs and suggest changes to the language.**

**Summary Consideration:**

Some commenter's expressed concern with potential for multiple violations of the standard due to a single event. The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.

Some suggestions were made to change specific VSLs or measures. The SDT modified VSLs for R3 and R10, but did not modify the other measures or VSLs.

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| The Midwest ISO | No | The tolerances included in the VSLs for R10 should be moved into the requirement itself. |
| **Response:** The SDT has modified the VSL to be consistent with the corresponding VSL for MOD-001 R8 | | |
| FirstEnergy | No | In the Severe category VSLs for requirement R3, we suggest removing the word "detailed" when referring to detailed modeling data as it is ambiguous and subjective. |
| **Response:** The Severe VSLs for R3 were corrected to match the requirement. | | |
| PJM | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations — this language to be added to the standard. Add a new item 6 to section A of MOD-001. For example a review of MOD-001 R2 and R8 and MOD-30 R10 should be performed for determination of multiple violations resulting from one event. |
| **Response:** The SDT does not believe it is within the drafting teams scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events. | | |
| ISO RTO Council/Standards Review Committee (SRC) | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but the IRC has a concern regarding the possibility of multiple violations resulting from a single event. The IRC requests that the potential for double counting of violations for a single event be eliminated. |
| **Response:** The SDT has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single | | |

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| events. | | |
| Ontario IESO | No | We have the following comments on the VSLs: a. R1: The VSLs are proper for this requirement. However, the Measure needs to be fixed so that they correspond to the VSLs. Please see our comments on M1 under Q1.<br>**Response:** The phrase, "and information on how sources and sinks are accounted for" was added to M1.<br><br>b. R2: We suggest the VSLs for R2 be rewritten, and where necessary, restructure R2 altogether to facilitate development of VSLs. For example, R2.1 is only one of the 6 subrequirements of R2, yet a condition that "The Transmission Operator did not include six or more Flowgates in its AFC calculations that met the criteria described in R2.1." would put the TOP to a Severe violation despite the TOP might have met all the remaining 5 subrequirements. Another example is that the TOP is more than 9 month late in establishing the list of internal Flowgates but has otherwise met all the other subrequirements. Further, there are far too many single condition that would put a TOP to Severe violation despite it may have et all the other conditions, and there is no violation level assigned to failing R2.5.1, which is to update TFC when notified of a rating change. A major rewrite of this set of VSL in conjunction with restructuring R2 appears to be an appropriate course for the SDT.<br>**Response:** The VSLs have been restructured such that the "OR" was replaced with a bulleted structure. In this manner, not ALL sub-requirements must be violated to receive a Severe VSL, but also ensures that violation of multiple sub-requirements will only result in a single Severe VSL. A VSL has been added for R2.5.1 and M6 had been modified to include it. One of the Severe VSLs has been removed because it was incorrect.<br><br>c. R3: Similar situation as in R2. R3 has 5 subrequirements and hence failing just one of them (except R3.1 for which VSLs are progressive (graded)) should not be assigned a Severe level. There needs to be consideration given to failing some combination of them for which Low, Moderate and High VSLs should be assigned. Unlike R2, R3 has a simpler structure and hence may not need to be restructured to facilitate proper assignments of VSLs.<br>**Response:** The VSLs for 3.2 and 3.3 have been graded and The VSLs have been restructured such that the "OR" was replaced with a bulleted structure which ensures that violation of multiple sub-requirements will only result in a single Severe VSL. The VSL for R3.5 has been corrected to match the requirement.<br><br>d. R5: This requirement has 3 subrequirements. It is generally expected that failing one of the 3 subrequirements would result in a Moderate VSL, 2 for a High VSL and all 3 for a Sever VSL as opposed to seeing only the graded VSL for failing R5.2. Furthermore, there may not be a large number of |

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| | | outages/retirements (for example 26-50) occurring during a modeling period within the total area that a TSP needs to model. Some VSLs for R5.2 may not be applicable for some TSPs even they may miss all the outages/retirements within the total area that it needs to model. Suggest the SDT revise this set of VSLs to take into account failing any combination of the 3 subrequirements, and the range of area size (and hence the total number of possible outages within a period) that a TSP needs to model.<br><br>**Response:** The VSLs have been structured this way to allow a graded approach for R5.2. There would be few instances where a VSL for R5.2 is not applicable for a TSP, and there is not a clear way to quantify the total number of possible outages within a period. The VSLs have been restructured such that the "OR" was replaced with a bulleted structure which ensures that violation of multiple sub-requirements will only result in a single Severe VSL.<br><br>e. R6: For these VSLs to be appropriate, please see our comments and suggestion for changes on M13 under Q1.<br>**Response:** Please see response to Q1.<br><br>f. R7: For these VSLs to be appropriate, please see our comments and suggestion for changes on M14 under Q1.<br>**Response:** Please see response to Q1.<br><br>g. R8: The VSL has a condition that there is a violation if additional elements are used in the calculation of firm AFCs. Not allowing the use of additional elements is not stipulated in the requirement. Suggest to remove this condition from the VSL, or add this requirement to R8.<br>**Response:** The condition is implied in R8; the requirement is to use the stated algorithm and if additional elements were used, it would be a different algorithm.<br><br>h. R9: Same comment on R8 also applies here for calculating non-firm AFCs.<br>**Response:** The condition is implied in R9; the requirement is to use the stated algorithm and if additional elements were used, it would be a different algorithm.<br><br>i. R10: The VSLs as written indicates that failing any one of the 3 beyond some threshold levels would constitute a Severe violation. This is not consistent with the general principle that failing all subrequirements would result in a Severe violation. Suggest the SDT revise this set of VSLs to achieve |

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| | | consistency with the general principle.<br>**Response:** The SDT has modified the VSL to be consistent with the corresponding VSL for MOD-001 R8<br>j. R11: Please see our comment on M18 under Q1. If the wording to M18 is revised as suggested, the wording for the VSL condition should be changed accordingly.<br>**Response:** The VSL has been changed accordingly. |
| **Response:** Please see in-line responses. | | |
| SERC ATCWG | Yes | |
| WECC Market Interface Committee / Sub Commtt? ATC Task Force | Yes | |
| Kansas City Power & Light | Yes | |
| WECC Market Interface Committee ATC Task Force | Yes | |
| Manitoba Hydro | Yes | |
| NPCC Regional Standards Committee | Yes | |
| Public Service Commission of South Carolina | Yes | |
| Duke Energy Corporation | Yes | |
| Oncor Electric Delivery | Yes | |
| Bonneville Power | Yes | |
| Entergy Services Inc. | Yes | |
| MRO NERC Standards Review Subcommittee | Yes | |

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| American Transmission Company | Yes | |
| Texas-New Mexico Power Company | Yes | |
| EPSA | | no comment |

**4. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-030.**

**Summary Consideration:**

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

Some entities expressed concern with the ability to share data without non-disclosure agreements in place. In general, the SDT expects that a Transmission Operator should already have appropriate agreements in place with its Transmission Service Provider to address this. If such contracts are not in place, the standard does not prohibit nor require them, but entities are still responsible for meeting the requirements in the standard.

Some entities expressed concern that MOD-030 was more stringent than MOD-028 and MOD-029. The SDT explained that the methodologies were different, and therefore had different ways of documenting requirements, or different processes for meeting reliability goals, but in general, were consistent.

Some entities expressed concern with the effective date and the "concurrent" implementation being dependent on "all" regulatory authorities. The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals.

Some entities suggested that the standard should define how AFC is calculated, but not that it should be calculated. The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives.

Some entities suggested that the standard should not apply to non-firm ATC. The SDT stated that removal of non-firm from the standard could allow for unchecked selling of non-firm service, which could lead to concerns within real-time.

Some entities questioned whether the standard should be modified to address "accepted" reservations, in addition to confirmed reservations. The SDT responded that the standard does not prohibit the TSP from maintaining an "internal" ATC value for use in approving reservation requests that includes these Accepted reservation. This is the manner FERC has indicated to be an appropriate way for dealing with "Accepted" reservation in its regulations. To the extent ATC believes these numbers should be posted, the SDT believes ATC should develop a NAESB request for the posting of this information.

Some entities did not understand the establishment of TFC for non-thermal limits. The SDT explained that, for example, the SOL limit could actually be a voltage limit, and this limit would have to be translated into a MW value to be assigned to a Flowgate in order to "respect the SOL".

The drafting team provided a summary of the use of time horizons to address some comments.

Some entities pointed out that as written, the requirement to include flowgates that have been in TLR would require the inclusion of flowgates that might be outside the scope of the transmission model if an entity chose to model beyond the requirements in the standard. The drafting team modified R2.1.3 to require only inclusion of those flowgates that have been subjected to an interconnection wide congestion management procedure AND meet the minimum model scope requirements of R3.4 and R3.5. Therefore even if the TO chooses to model a larger area, those flowgates that have been subjected to an interconnection wide congestion management procedure that are in that wider area not specified by R3.4 and R3.5 do not have to be included.

Some entities questioned if the standard was in conflict with TOP-002 R12. The SDT believes that the MOD standards are the appropriate location for the reference to SOLs with regard to transfer capability. Additionally, TOP-002 R12 applies to the Transmission Service provider while R2.4 applies to the Transmission Operator. The drafting team believes that the TFC will be based on the most constrained facility's SOL (thermal, voltage, or stability based) for the monitored facilities considered in the flowgate, so no change is needed.

One entity questioned the structure of the source/sink modeling requirements. The SDT explained the intent of the requirements, and provided examples of the manner in which various market models could be accommodated.

Several entities did not understand why MOD-001 and MOD-030 both had requirements related to recalculation frequency. The SDT explained that these two requirements are different, and address fundamental differences between the methodologies.

Some entities suggested that the allowance for 80 hours described in the MOD-001 ATC calculation schedule should apply to MOD-030's R10 as well. The SDT has modified MOD-030 R10 to allow for the annual allowance specified in MOD-001 R8.

The concept of "temporary" flowgates was raised, and whether or not the standard required temporary flowgate to be maintained indefinitely. The SDT stated that provided the conditions that cause the temporary flowgate to meet the criteria in R2.1 are no longer in existence, the flowgate could be removed immediately. Note that if the temporary flowgate had an interconnection-wide congestion management procedure invoked, the 12-month criteria would apply.

| Organization/Group | Question 4 Comments: |
|---|---|
| WECC Market Interface Committee / Sub Commtt? ATC Task Force | Should the term "dispatch order" in MOD-30, R6.1.2 be a capitalized defined term? |
| **Response:** The SDT has capitalized the phrase as suggested. | |
| WECC Market Interface Committee ATC Task Force | Should the term "dispatch order" in MOD-030, R6.1.2 be a capitalized defined term? |
| **Response:** The SDT has capitalized the phrase as suggested. | |
| CenterPoint Energy | The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy |

| Organization/Group | Question 4 Comments: |
|---|---|
| | is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a single control area. |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Flowgate methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT beleives that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| ERCOT ISO | I suggest modifying the Applicability section to state:"4.1.1 Each Transmission Operator with ATC Path(s) that uses the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for ATC Paths. "4.1.2 Each Transmission Service Provider with ATC Path(s) that uses the Flowgate Methodology to calculate ATCs for ATC Paths." |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Flowgate methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |

<table>
<tr><th>Organization/Group</th><th>Question 4 Comments:</th></tr>
<tr><td>Oncor Electric Delivery</td><td>This standard should not apply to ERCOT for the reason expressed in question 1.</td></tr>
<tr><td colspan="2">Response: This standard is intended to apply to all entities that have chosen to implement the Flowgate methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>Texas-New Mexico Power Company</td><td>This standard should not apply to ERCOT for the reason stated in Question 1.</td></tr>
<tr><td colspan="2">Response: This standard is intended to apply to all entities that have chosen to implement the Flowgate methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT beleives that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>Electric Service Delivery</td><td>These comments are filed on behalf of City of Austin d/b/a Austin Energy to address proposed NERC 5 MOD Standards. Austin Energy is a municipally owned electric utility and a transmission service provider with the Electric Reliability Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with no explicit transmission services being sold. Current ERCOT market rules allow open transmission access to all loads and resources. ERCOT will continue to operate as a Single Balancing Authority under Nodal market design. Accordingly, as explained in more detail below, the NERC 5 MOD Standards should not be applied to ERCOT and transmission service providers within ERCOT under its current or proposed Nodal market design. Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to</td></tr>
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| Organization/Group | Question 4 Comments: |
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| | regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations .Applicable definitions: According to NERC Reliability Standards Glossary of Terms, Available Transfer Capability (ATC) is defined as: ?A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability (TTC) less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows?. TTC is defined as: the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions. CBM is defined as the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. TRM also is a component of ATC defined as: that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. Comments: ERCOT is an interconnection and a region with no synchronous AC ties with any other interconnections. In July 2001, based on a deregulated Retail and restructured Wholesale Markets, the ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT market is designed such that there are no explicit transmission services being sold, hence, Available Transfer Capability (ATC) is not a measure used in a commercial activity within the ERCOT market. The current ERCOT market rules allow open transmission access to all eligible loads and resources without considering any specific Transmission Service Provider (TSP). Transmission facilities ratings are based upon individual branch element designs and in cases of dynamic ratings, ambient conditions are also considered. ERCOT has several DC ties and an asynchronous tie using a Variable Frequency Transformer (VFT); however, the associated interchange capabilities are planned and coordinated by the TSPs involved. The current ERCOT Zonal Market uses a flow based congestion management methodology to predict potential congestions in the Day Ahead and Adjustment Periods. During the operating period, generation shift factors are used to determine the dispatch needed to remain within the constrained limits. The local congestions are managed using full AC load flow analysis and unit specific redispatch.MOD-001-1 is entirely about methodology and calculation of ATC, therefore, this standard is not applicable to ERCOT.MOD-008-1 covers Transmission Reliability Margin (TRM) methodology calculation. Mathematically, ATC is defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin (CBM). Therefore, TRM also is not applicable to ERCOT.MOD-028-1 covers Area Interchange calculation Methodology. Since ERCOT is a single control area, Area Interchange calculation is not applicable.MOD-029-1 covers Rated System Path Methodology, which is used to calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT.MOD-030-1 covers Flowgate methodology calculation of ATC, and therefore, is not applicable to ERCOT.ERCOT is currently transitioning to a Nodal Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a Security Constrained Economic Dispatch (SCED) approach to dispatch individual |

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| | generating units and manage congestion. In the Nodal Market, ERCOT will still operate as a Single Balancing Authority. This again will not use ATC methodology, and aforementioned standards are not applicable to ERCOT in its ensuing Nodal Market. Therefore, Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Flowgate methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| Brazos Electric Power Cooperative, Inc. | Brazos Electric believes that the concept of the Flowgate Methodology to support the calculation of Available Transfer Capabilities (ATCs) for ATC Paths is not applicable to a single-control area operation like ERCOT. To address this issue, the Applicability section could have a clarifying statement that only TOPs or TSPs conducting area to area operations and hence have responsibility for ATC Path(s) are subject to the requirements of MOD-030 if it uses a Flowgate Methodology. |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Flowgate methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |

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| California ISO | R 3 – Should the actual Flowgate model made available to TSP upon request ONLY under NDA??? Confidential Model and access???<br>**Response:** In general, the SDT expects that a Transmission Operator should already have appropriate agreements in place with its Transmission Service Provider to address this. If such contracts are not in place, the standard does not prohibit nor require them, but entities are still responsible for meeting the requirements in the standard.<br><br>R 11 – SDT should clarify that MOD 30 R11 only specifies HOW AFC be converted and DOES NOT REQUIRE that it must be converted, as intent of SDT. MOD 30 does not REQUIRE that all AFCs be converted and posted to OASIS, irrespective of whether or not the ATC Path definition applies to internal lines for those with a flow based model.<br>**Response:** The drafting team has made R11 as clear as possible – it would not be appropriate in a requirement to specify what is not required. |
| **Response:** Please see in-line responses. | |
| Manitoba Hydro | MH echoes the concerns raised and documented by MISO that MOD-030 requirements are generally more stringent than those outlined for MOD-028 and MOD-029. |
| **Response:** Please see responses to MISO's comments. In general, the SDT believes the methodologies are different but not necessarily more stringent. | |
| FirstEnergy | FirstEnergy appreciates the Standard Drafting Team's decision to move to a formal comment period based on the prior initial ballot feedback. We commend the team for moving quickly to respond to the ballot comments and providing the industry a revised set of standards to review and comment .We suggest striking the words "short term use" from the purpose statement as we believe this methodology should also be valid in the planning horizon as a longer term projection of TFC and AFC.<br>**Response:** Transfer capability is only required to be calculated for 13 months so it was not thought appropriate to mandate that this standard be used beyond that, however, it also does not preclude using this method in the planning horizon.<br><br>Regarding the revision to the Effective Date, while FirstEnergy agrees that there is a need to ensure that the standard is implemented consistently across the entire continent we are concerned with the Effective Date being subject to approval of ALL regulatory authorities. We believe an appropriate Implementation Plan should reflect a period of time beyond the NERC Board of Trustee approval date that would reflect when the requirements are considered mandatory and enforceable. The timeline should allow sufficient time for |

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| | regulatory authority reviews, with the intent of sanctions also being enforced in conjunction with the conclusion of the implementation period. However, a delay from a given regulatory agency should not impact when the requirements are considered mandatory and enforceable for the bulk electric system.<br>**Response:** The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals. |
| **Response:** Please see in-line responses. | |
| AEP | The Purpose statement is unclear and perhaps nonsensical. Is the purpose "to increase consistency and reliability in the development of documentation"? or "to support analysis and system operation?" What entities? "short term use"? Suggestion: Purpose: To ensure consistency of calculation of those entities employing Flowgate Methodology pursuant to MOD-001 R1. |
| **Response:** AEP has inaccurately quoted the language of the "Purpose" statement as being for "the development *of documentation*" (emphasis added); whereas the actual Purpose statement is to promote "the development and documentation *of transfer capability calculations*." (emphasis added). This statement clearly aligns with FERC's Order 693, P. 1015 wherein FERC states the purpose of the ATC suite is to promote "consistency and transparency for ATC calculations." As for the ambiguity of applicable entities in the Purpose statement, AEP is reminded that the Applicable entities are clearly stated in the Applicability section – not the Purpose section. As for short-term, FERC suggests that short-term is operational whereas long-term is planning in nature. Order 693, P. 1040. See also Order 890, P. 292 – 295. | |
| PJM | The MOD standards extend into areas that should be covered and addressed by NAESB Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices, and not included in the NERC Standards as reliability based requirements (see specific details for MOD-001 R2 and R7 and MOD-030 R10 in the Specific Comments sections below).<br>**Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives.<br><br>Non-firm should be removed from this reliability standard.<br>**Response:** Removal of non-firm from the standard could allow for unchecked selling of non-firm service, which could lead to concerns within real-time. |

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| | – Reservations in "Accepted", as well as, "Confirmed" status should be included in ATC calculation (see MOD030 R6.3). Once the transmission provider has accepted the request, the provider is now required to provide service; therefore, not decrementing for accepted TSRs could result in over commitment.<br>**Response:** The standard does not prohibit the TSP from maintaining an "internal" ATC value for use in approving reservation requests that includes these Accepted reservation. To the extent the IRC believes these numbers should be posted, the SDT believes the IRC should develop a NAESB request for the posting of this information. |
| **Response:** Please see in-line responses. | |
| Bonneville Power | BPA thanks the drafting team for clarifying that MOD-030 does not require the conversion of AFC to ATC and agrees with your assessment that there is no reliability need for such conversion. In addition, BPA respectfully submits the following observations and suggestions:<br><br>a. There appears to be some conflicting overlap between R2.1.–R2.1.4.2. in MOD-030-1 and the System Operating Limits (SOL) Standards (FAC-010-1 and FAC-011-1). It is unclear to BPA that there is any reliability-based need for the identification of more Flowgates than are needed to protect SOLs. To that end, BPA suggests the following modifications to and renumbering of the above mentioned requirements: R2.1. – Identify Flowgates used in the AFC process based, at a minimum, on the following criteria: R2.1.1. – As necessary to protect established System Operating Limits (SOLs) or 2.1.1.1 Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates. 2.1.1.1.1. Use first Contingency assumptions consistent with those first Contingencies used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems. 2.1.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate. 2.1.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology. 2.1.1.2.1. Use first Contingency assumptions consistent with those first Contingencies used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems. 2.1.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate. R2.1.2. Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, |

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| | unless the limiting Element/Contingency combination is accounted for using another ATC methodology. R2.1.3. Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where: 2.1.3.1. If the coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and – Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or – A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate. – The Transmission Operator may utilize distribution factors less than 5% if desired. 2.1.3.2. – If the limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.<br>**Response:** The requirement ": R2.1.1. – As necessary to protect established System Operating Limits (SOLs) or…" is too subjective to be used as an alternative to the criteria currently listed in the requirements. R2.1.3 has been corrected to be consistent with R2.1.2 as requested.<br><br>b. R2.4 has two bulleted sub-requirements that should either be numbered with a brief description provided as to how one would "respect the SOL" vs. simply setting the TFC equal to the SOL; or collapsed into R2.4 as follows: R2.4. Establish the TFC of each of the defined Flowgates as equal to: the System Operating Limit (SOL) of the Flowgate.<br>**Response:** R2.4 is a requirement for the establishment of a TFC for *each* Flowgate, so for each Flowgate you would select one or the other of the bullets, therefore the bullets should not be replaced with numbers. For the second bullet, the SOL limit could actually be a voltage limit, and this limit would have to be translated into a MW value to be assigned to a Flowgate in order to "respect the SOL".<br><br>c. The Time Horizons listed for all requirements should include the "Long-term Planning" Horizon, as ATC or AFC is to be calculated beyond the seasonal window.<br>**Response:** The use of "Time Horizons" in this standard is in the form of a compliance element, and refers to the manner in which compliance evaluates the implications of a violation of the standard. In this context, time horizon has to do with the urgency of addressing a violation, e.g., how quickly a violation needs to be rectified. Together, the Violation Risk Factor and Time Horizon aid a compliance auditor in determining sanctions. Accordingly, the SDT believes that the appropriate horizon for compliances does not include "Long-term Planning."<br><br>d. Balancing Authorities may be appropriately identified as Applicable Entities in this MOD and request that the |

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| | Standards Drafting Team provide an explanation as to why they are not listed.<br>**Response:** The SDT is uncertain what tasks BPA would assign to the Balancing Authority. To the extent that BPA has suggested requirements or tasks for the BAs to perform, the SDT suggests that BPA draft a SAR to incorporate those requirements in a future revision to the standard. |
| **Response:** Please see in-line responses. | |
| Ontario IESO | We commend the SDT for having worked very hard to try to meet FERC's earlier deadline, and for taking very positive steps responding to industry comments received from previous round of posting for comment and from the failed balloting process. However, owing to the number and size of the standards, there is a great potential for inconsistent treatment to the requirements, measures and VSLs among the standards. After reviewing all 6 standards and offering comments, we've found that there is quite a bit of inconsistency among the standards. For example, for a similar process, some requirements in a standard have only one level of subrequirements while in another standard there are two levels. In some standards that have requirements that contain subrequirements, there is only one measure while in another standard, similar process having similar requirement structure may have multiple measures. Still the vast majority of inconsistency is found in the VSLs: for similar requirement structure and content, some have appropriately graded VSLs while some have binary (none or Severe) VSLs; some have graded VSLs that is a function of the number of subrequirements violated while others have VSLs that is determined by the extent of violation of any one of the subrequirements. The inconsistent wording among the requirements, their measures and VSLs is another area of concern. We realize the SDT is still working with a tight timeline. Nonetheless, we feel that the needed time must be spent to review the structure and quality of these standards to support measurability and the ability to develop proper VSLs. Unlike the development of VSLs for the approved standards – a process that did not allow for changing the requirements, the ATC SDT has the freedom to change the requirements as it sees necessary to facilitate proper development of measures and ease of VSL development thereby achieving a set of quality standards that are measurable and enforceable. We therefore suggest the SDT do spend some time to refine these standards to improve their quality rather than trying to post them in short order to get ahead on the timeline. |
| **Response:** Many comments were received and were incorporated that improved the quality of the standards. | |
| The Midwest ISO | The Midwest ISO believes that MOD-030 continues to be more stringent than MOD-028 and MOD-029. |
| **Response:** Please refer to the responses to the comments that detailed specific examples of these concerns in question 1. | |
| MRO NERC Standards Review Subcommittee | 1. The MRO continues to have issues with the overall approach on this standard in combination with the MOD-028. As previously indicated in prior comment periods, the MRO has Transmission Service Providers that manage the levels of transmission service to a reliable level with flowgates and then establishes border control area-to-control area flows to contract path levels so that contractual rights are not exceeded. The |

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| | MRO reads the MOD-028 standard to require the application of the MOD-028 methodology for its control area-to-control area path postings while MOD-030 standard is used for the flowgate postings. The MRO understands from a discussion with a member of the SDT that in actuality the intent is that the MOD-030 would be used for flowgate calculations and that these quantities could be converted into the ATC path quantities for the control area to control area paths from border companies to outside the Transmission Service Providers area. This application of the flow gate methodology to possibly generate all postings in for a Transmission Service Provider including drive out is not clear from the standards and should be clarified in MOD-030 and possibly MOD-028.<br>**Response:** The SDT believes this to be clear. MOD-001 R1 allows for an entity to implement the methodology or methodologies of their choice, subject to the limitations describe. The applicability of MOD-028 and MOD030 indicates that they only apply to entities who have elected to use the methodologies. MOD-030 provides a mechanism for converting AFCs to path-based ATC values.<br><br>2. The MRO commends the SDT in making significant changes to this standard and reissuing it for comment. The MRO believes the eventual standard that is approved will serve the industry and customers better as a result.<br>Response: Thank you for your supportive comment.<br><br>3. The MRO acknowledges the consistent application of spelling out the full term followed by the abbreviation or acronym in brackets on the first time use. With the goal of consistency across all the standards.<br>Response: The SDT has attempted to apply this consistently throughout the standards.<br><br>4. R6 and R7 – Overall, both requirements as written are unclear. The MRO asks that the standards drafting team specify what assumptions are referenced or else delete these requirements. The MRO notes that these requirements are covered by FERC order #890 anyway.<br>**Response:** The SDT believes R6 and R7 are clear, and note that they do not refer to assumptions.<br><br>5. In the Purpose field, why specify for short term use only? The MRO believes this methodology is valid for the planning horizon also.<br>**Response:** ATC is only required to be calculated for 13 months so it was not thought appropriate to mandate that this standard be used beyond that. However, it also does not preclude using this method in the planning horizon. |

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| | 6. R2 – In general, we believe this is not treated equally comparing to MOD-028 and MOD-029. There isn't a minimum criterion on what contingencies have to be included in MOD-028 or MOD-29. All they need to do is to include in their ATCID. Why can't flowgate methodology do the same thing!.<br>**Response:** MOD-028 and MOD-029 do not limit the subset of limiting elements and contingencies that are considered in ATC calculations; MOD-030, on the other hand, bases the calculation of AFC on a limited subset of limiting elements and contingencies, therefore R2 of MOD-030 must contain criteria for selecting this subset of flowgates.<br><br>R2.1.3 – The MRO believes that this requirement is too burdensome and stringent, and sometimes have no effect on a TO or TSP. If a TO chooses to model the topology for a TO or TSP far removed from its respective region, why is it mandated that all flowgates with TLR be honored. This requirement also gives no service for an instance where a TLR may occur due to a temporary condition such as a forced outage. This will greatly increase the number of flowgates that each TO will have to account for in their load flow calculations without much perceived benefit.<br>**Response:** The drafting team has modified R2.1.3 to require only inclusion of those flowgates that have been subjected to an interconnection wide congestion management procedure AND meet the minimum model scope requirements of R3.4 and R3.5, therefore even if the TO chooses to model a larger area, those flowgates that have been subjected to an interconnection wide congestion management procedure that are in that wider area not specified by R3.4 and R3.5 do not have to be included.<br><br>8. R2.2 – Edited the statement to read: At a minimum, establish the list of Flowgates at least once per calendar year. The MRO believes that this would be a clearer requirement.<br><br>9. R2.3 – Edit the statement to read: At a minimum, establish the list of external Flowgates that have been requested within thirty calendar days from the request. The MRO believes that this would be a clearer requirement.<br>**Response:** The drafting team believes that "to create, modify or delete" appropriately adds to the clarity of these requirements.<br><br>10. R2.4 – The MRO believes that this requirement is identical to R12 in TOP-002. Since TOP-002 R12 will not be retired, R2.4 in MOD-030 is redundant and should be removed. However, if the DT does not agree, The MRO would then comment that for thermal limits, the thermal rating of the Flowgate should be used and |

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| | not the SOL.<br>**Response:** The SDT believes that the MOD standards are the appropriate location for the reference to SOLs with regard to transfer capability. Additionally, TOP-002 R12 applies to the Transmission Service provider while R2.4 applies to the Transmission Operator. The drafting team believes that the TFC will be based on the most constrained facility's SOL (thermal, voltage, or stability based) for the monitored facilities considered in the flowgate, so no change is needed.<br><br>11. R4 – The MRO has two comments related to this requirement: A. The MRO has observed that a similar requirement is not in MOD-029. We feel that TSPs that follow the Rated System Path methodology should also be subjected to this requirement. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies.<br>**Response:** R4 specifies how transmission service reservations shall be modeled. The Rated System Path method does not use simulation to analyze reservations, so a similar requirement would not make sense in MOD-029.<br><br>B. The sub-requirements (identified with a dash in the standard) seem to be written as though they are mutually exclusive. The MRO believes that a Source or Sink identified in a reservation that is discretely modeled can still be mapped to an "equivalence" or "aggregate" representation in the model.<br>**Response:** They are mutually exclusive. However, the SDT believes that the scenario you describe is not problematic. In cases where MISO is modeling imports, we expect that the reservation would have a source outside MISO and a sink of MISO. This would be acceptable, as "MISO" would be discretely modeled as a system. In cases where MISO is modeling imports, we expect that the reservation would have a source of MISO and a sink outside MISO. This would also be acceptable. For internal transactions, we would expect that a source of MISO and a sink of MISO would be invalid from a modeling perspective, and effectively result in zero flow (a transfer distribution factor of zero). To the extent MISO wanted to model internal BA to BA flows, it could utilize the POR and POD, provided this convention was described in the ATCID. In some cases where entities use the source and sink fields for financial purposes, the SDT is aware that other entities use the POR or POD to address this as well, which is acceptable provided it has been so defined in their ATCID pursuant to R1.2.<br><br>12. R5.2 – Language should be added to say that this requirement applies if the data is supplied by the entities owning the information.<br><br>13. R6.2/R6.4/R6.6/R7.2/R7.4/R7.6 – The MRO has two comments related to these requirements: A. |

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| | Language should be added to state that the requirements are applicable only if the other TSPs provide necessary information.<br>**Response:** The standard is requiring that entities request this information of their neighboring entities. To the extent entities do not provide it, the other entities would be out of compliance with R9 of MOD-001.<br><br>B. The MRO has observed that similar requirements are not in MOD-028 or MOD-029. We feel that TSPs that use MOD-028 and MOD-029 should also be subjected to this requirement. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies.<br>**Response:** The SDT notes that similar language is found in MOD-028 R3, R8, and R9, and in MOD-029 R1, R5 and R6. The SDT notes that the unique nature of Flowgates (having to refer to the impact of a reservation, rather than the nominal value itself) can lead to much more verbose requirements. Additionally, many of the analyses of third-party impacts undertaken in the Flowgate methodology to determine AFC are also undertaken in the other methodologies – but as part of the determination of TTC.<br><br>14. R10 – First of all, all three methodologies should have the same calculation frequency and the same allowance for outages. The MRO believes that a load flow for hourly values shall be conducted at least once per day. Lowering the requirement for all to once per hour is overly burdensome. This requirement should be removed as there is no companion requirement in MOD-028 and MOD-029. Second, any forgiveness/tolerance for error should be included in the requirement instead of the VSL table because it is the requirement that determines whether the entities are in compliance, NOT the VSL table. Third, if this requirement has to stay, it should use similar outage/maintenance allowances for hourly values as in MOD-001.<br>**Response:** These two requirements are different, and address fundamental differences between the methodologies. MOD-001 discusses the recalculation of ATC on a fixed schedule unless the components in the ATC equation change. MOD-030 R10 addresses calculation of AFC on a schedule consistent with the MOD-001 requirement. However, there is additional information in the MOD-030 requirement that is specific to that methodology. MOD-030 R10 does not require full recalculation of the distribution factors through an update of the transmission model; updates of the transmission model occur on a separate schedule as defined in MOD-030 R3. MOD-028 addresses this similarly through the recalculation of TTC on a separate schedule as defined in MOD-028 R5. MOD-029 addresses changes to topology through adjustments to TTC. Because of these technical differences between the methodologies, the SDT believes having the two requirements is appropriate.<br><br>The SDT has modified MOD-030 R10 to allow for the annual allowance specified in R8. |

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| | 15. R11 – The formula, as it is written, would result in using different flowgates to convert AFC to ATC and TFC to TTC. The MRO believes that we should use the same flowgate for both conversions. The formula should be used only for AFC-ATC conversion. TTC should be calculation by dividing TFC by DF for the same most ATC-limiting flowgate.<br>**Response: T**he current formula is a valid approach for calculating TTC. Implementing as suggested would result in the TTC changing every time the most limiting flowgate changed.<br><br>16. M17 – Should reference calculating AFC not ATC.<br>**Response:** This change has been made. |
| **Response:** Please see in-line responses. | |
| Southwest Power Pool | R2.1.3. Any limiting Element/Contingency combination within the Transmission model that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months.R2.1 addresses criteria for identifying flowgates used in the AFC process. Certain operating conditions cause the use of temporary flowgates. Coordination tests may be executed between entities for a temporary flowgate which will be included in AFC calculations and congestion management systems. Would these situations require these temporary flowgates to remain in AFC processes even after the temporary conditions return to normal (transmission elements return to service)? In some cases, temporary flowgates created for short-term may not necessarily fall under the criteria established in R2.1 but should be allowed because of their immediate need in reliably operating the transmission system. |
| **Response:** No, there is no minimum duration for which a flowgate must be considered. Provided the conditions that cause the temporary flowgate to meet the criteria in R2.1 are no longer in existence, the flowgate could be removed immediately. Note that if the temporary flowgate had a interconnection-wide congestion management procedure invoked, the 12-month criteria would apply. | |
| American Transmission Company | The first time that each abbreviation or acronym is introduced, the full terminology should be stated followed by the abbreviation or acronym in brackets (i.e. TFC).<br>**Response:** This change has been made.<br>Modification to Applicability Section: 4.1.1 Each Transmission Operator that uses the Flowgate Methodology4.1.2 Each Transmission Service Provided that uses the Flowgate Methodology. We believe that the remaining language ("to support the calculation of ATC for ATC Paths) can be deleted because of the subsequent changes to MOD-001-1. The SDT changes MOD-001-1 to accommodate both ATC and AFC. Please see our comments to MOD-001-1 that if implemented by the SDT should make the deletion acceptable. |

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| | **Response:** The Applicability section has been modified to reference AFCs and Flowgates.<br><br>Proposed Effective Date: Please see our comments in MOD-001-1 about the proposed effective date.<br>**Response:** Please see the response to the comments in MOD-001. |
| **Response:** Please see in-line responses | |
| American Public Power Association | Great work - thanks to the SDT |
| **Response:** Thank you for your supportive comment. | |
| EPSA | no comment |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC Conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adopts MOD-001-1. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Rated System Path Methodology:** The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

## A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

**R1.1.1.** Includes at least:

1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (equivalent representation is allowed).

1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (equivalent representation is allowed).

**R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.

**R1.1.3.** Models all generation Facilities larger than 20 MVA in the studied area.

**R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the ATCID.

**R1.1.5.** Uses Load forecast by Balancing Authority.

**R1.1.6.** Uses Transmission Facility additions and retirements.

**R1.1.7.** Uses Generation Facility additions and retirements.

**R1.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

**R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

**R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

**R2.** The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

**R2.1.1.** When modeling normal conditions, do not model any Transmission Element above 100% of its continuous rating.

**R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

**R2.1.3.** Uncontrolled separation shall not occur.

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

**R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

**R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** Verify that the TTC for the ATC Path being studied does not adversely impact the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

**R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NL_F$** is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$NITS_F$** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_F$** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_{NF}$** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + counterflows_F$$

**Where**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$Counterflows_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

**R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC – ETC_F – ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$Counterflows_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC used in its ATC calculations, as required in R1. (R1)

**M1.2.** The Transmission model produced must include the areas listed in R1.1.1 1 (or an equivalent representation, as described in the requirement) (R1.1)

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

**M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

**M7.** The Transmission Service Provider must be capable of demonstrating that for any calculation of firm ETC made in the previous 60 days, the Transmission Service Provider can recalculate the individual value of the firm ETC for a specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R5)

**M8.** The Transmission Service Provider must be capable of demonstrating that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the non-firm ETC for a specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R6)

**M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc.). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

**M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)

The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)

The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)

The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)

The Transmission Service Provider shall retain evidence for the most recent sixty days to show compliance with R5 and R6. (M7 and M8)

The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)

If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits

- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.<br>Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled. |
| R2 | N/A | N/A | N/A | The Transmission Operator did not calculate TTC using the process described in R2. |
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, ~~BUT~~**but**, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), ~~**BUT**~~ **but** not more than 2% of all ATC Paths or 2 ATC Paths (whichever is | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), ~~**BUT**~~ **but** not more than 5% of all ATC Paths or 3 ATC Paths (whichever is | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater). |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | greater). | greater). | |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized. |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15 MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25 MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25 MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35 MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35 MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45 MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45 MW, whichever is greater. |
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15 MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25 | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25 MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35 | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35 MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45 | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45 MW, whichever is greater. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | MW, whichever is greater. | MW, whichever is greater. | MW, whichever is greater. | |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |

## E. Regional Variances

None.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

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2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
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**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
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| 8. Board adopts MOD-001-1. | September 1, 2008 |

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## A. Introduction

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2. **Number:** **MOD-029-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities~~, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees~~.

## B. Requirements

**R1.** When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower~~Medium~~*] [*Time Horizon: Operations Planning*]

**R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

**R1.1.1.** Includes at least:

1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (equivalent representation is allowed).

1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (equivalent representation is allowed).

**R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.

**R1.1.3.** Models all generation Facilities larger than 20 MVA in the studied area.

**R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the ATCID.

**R1.1.5.** Uses Load forecast by Balancing Authority.

**R1.1.6.** Uses Transmission Facility additions and retirements.

**R1.1.7.** Uses Generation Facility additions and retirements.

**R1.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation ~~-~~within the studied time horizon.

**R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

**R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

**R2.** The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower~~Medium~~*] [*Time Horizon: Operations Planning*]

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

**R2.1.1.** When modeling normal conditions, do not model any Transmission Element above 100% of its continuous rating.

**R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

**R2.1.3.** Uncontrolled separation shall not occur.

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

**R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

**R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** Verify that the TTC for the ATC Path being studied does not adversely impact the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

**R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower~~Medium~~*] [*Time Horizon: Operations Planning*]

**R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower~~Medium~~*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

$\mathbf{NL_F}$ is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$\mathbf{ROR_F}$ is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

$\mathbf{OS_F}$ is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

$\mathbf{NITS_{NF}}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_{NF}$** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower~~Medium~~*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + \cancel{Counterflow}counterflows_F$$

**Where**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm Available Transfer Capability due to a change in the use of ~~Firm~~ Transmission Service for that period, as defined in Business Practices.

**$Counterflows_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

**R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + \cancel{Counterflow}counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Transfer Capability due to a change in the use of ~~Non-Firm~~ Transmission Service for that period, as defined in Business Practices.

**$Counterflows_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC used in its ATC calculations, as required in R1. (R1)

**M1.2.** The Transmission model produced must include the areas listed in R1.1.1 1 (or an equivalent representation, as described in the requirement) (R1.1)

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

**M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

**M7.** The Transmission Service Provider must be capable of demonstrating that for any calculation of firm ETC made in the previous 60 days, the Transmission Service Provider can recalculate the individual value of the firm ETC for a specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R5)

**M8.** The Transmission Service Provider must be capable of demonstrating that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the non-firm ETC for a specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R6)

**M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc.). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

**M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

~~**M7.**Each Transmission Service Provider shall produce the algorithms it used to calculate ETCs for Firm and Non-Firm Transmission Service, as required in R5 and R6, showing that only the variables allowed in R5 and R6 were used to calculate ETCs. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R5 and R6)~~

~~**M7.1.**Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ETCs in R5 and R6. (R5 and R6)~~

~~**M8.**Each Transmission Service Provider shall produce the algorithms it used to calculate firm and non-firm ATCs, as required in R7 and R8, showing that only the variables allowed in R7 and R8 were used to calculate ATCs. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R7 and R8)~~

~~**M8.1.**Production of the algorithms shall be in the same form and format used by the Transmission Service Provider to calculate ATCs in R7 and R8. (R7 and R8)~~

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

**–The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)**

-The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)

~~-~~The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)

~~-~~The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)

~~-~~The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)

~~-~~The Transmission Service Provider shall retain evidence for the most recent ~~three calendar years plus the current year~~ sixty days to show compliance with R5 and~~,~~ R6~~, R7 and R8.~~. (M7 and M8)

The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)

~~-~~If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

~~-~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

**The following processes may be used:**

- **Compliance Audits**
- **Self-Certifications**
- **Spot Checking**
- **Compliance Violation Investigations**
- **Self-Reporting**
- **Complaints**

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| **R1.** | **The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.**<br>**OR**<br>**The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.**<br>**Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.** | **The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.**<br>**OR**<br>**The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.**<br>**Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.** | **The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.**<br>**OR**<br>**The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.**<br>**Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.** | **The Transmission Operator ~~did~~ used a model that did not meet four or more of the modeling requirements specified in R1.1.**<br>**OR**<br>**The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model.**<br>**Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.** |
| **R2** | **N/A** | **N/A** | **N/A** | **The Transmission Operator did not calculate TTC using the process described in R2.** |
| **R3.** | **The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in ~~R4~~ R2 or any associated SOL for more than zero ATC Paths,** but, **not more than 1% of all ATC Paths or 1 ATC Path** | **The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in ~~R4~~ R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 2% of all ATC Paths or 2** | **The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in ~~R4~~ R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater),** but **not more than 5% of all ATC Paths or 3** | **The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than -5% of all ATC Paths or 3 ATC Paths (whichever is greater).~~the larger of 4 or more ATC Paths OR 5% or~~** |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | (whichever is greater).<br>~~the larger of 1 ATC Path OR more than 0% but less than 1% of all ATC Paths~~ | ATC Paths (whichever is greater).~~the larger of 2 ATC Paths OR 1% or more but less than 2% of all ATC Paths.~~ | ATC Paths (whichever is greater). ~~.the larger of 3 ATC Paths OR 2% or more but less than 5% of all ATC Paths.~~ | ~~more of all ATC Paths.~~ |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider ~~28 or~~ more than 28 calendar days after the report was finalized. |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15 MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25 MW, whichever is greater. ~~.N/A~~ | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25 MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35 MW, whichever is greater. ~~.N/A~~ | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35 MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45 MW, whichever is greater. ~~N/A~~ | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45 MW, whichever is greater.~~The Transmission Service Provider did not use all the elements defined in R5 when determining firm ETC, or used additional elements.~~ |
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25 MW, whichever is greater. ~~.N/A~~ | calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35 MW, whichever is greater. ~~.N/A~~ | calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45 MW, whichever is greater. ~~.N/A~~ | calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45 MW, whichever is greater.~~.The Transmission Service Provider did not use all the elements defined in R6 when determining non-firm ETC, or used additional elements.~~ |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).<br>~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).<br>~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).~~The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements.~~ |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | Path (whichever is greater).~~N/A~~ | not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).~~N/A~~ | not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).~~N/A~~ | greater).<br>~~The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements.~~ |

## E. Regional Variances

None.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

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## Implementation Plan for Standard MOD-029-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-029-1 — Rated System Path Methodology, which describes the Rated System Path methodology for determining ATC.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### Retired Standards

FAC-012-1 — Transfer Capability Methodology includes four requirements. MOD-029-1 incorporates the following requirements from FAC-012-1:

– R1 (Documentation of the Transfer Capability Methodology).

– R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

– R4 (Responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-029-1 becomes effective.

FAC-013-1 — Establish and Communicate Transfer Capabilities, includes two requirements. MOD-029-1 incorporates the following requirements from FAC-013-1:

– R1 (Calculation of the Transfer Capabilities).

– R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-029-1 becomes effective.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-029-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Implementation Plan for Standard MOD-029-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-029-1 — Rated System Path Methodology, which describes the Rated System Path methodology for determining ATC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## ~~Modified~~ Retired Standards

FAC-012-1 — Transfer Capability Methodology includes four requirements. MOD-029-1 ~~This standard~~ incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology).
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (Responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-029-1 becomes effective.

FAC-013-1 — Establish and Communicate Transfer Capabilities, includes two requirements. MOD-029-1 ~~This standard~~ incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities).
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-~~012~~013-1 is no longer needed and is being retired when MOD-029-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-029-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities~~, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001, MOD-028, MOD-029, and MOD-030 are approved by the NERC Board of Trustees~~. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

Please **DO NOT** use this form to submit comments on the current draft of MOD-029. Comments must be submitted by **May 15, 2008.**

If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-452-8060.

**Background Information — MOD-029 — Rated System Path Methodology**. (A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection.)

An initial ballot of MOD-029-1 — Rated System Path Methodology was conducted March 3-12, 2008 and there were several suggestions for modifying the standard that were submitted with ballots. The drafting team withdrew the standard from the ballot process, and made several changes to the standard based on stakeholder comments, including the following:

1. Several VRFs were changed from "Medium" to "Lower" in response to industry comments. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
2. A more graded approach was applied to the VSLs where appropriate.
3. During the review of the VSLs and Measures, it was determined that the measures for R5, R6, R7, and R8 did not adequately measure compliance with the requirements. The drafting team updated the measures and VSLs to ensure that they captured the need to have accurate and valid numbers used in the requirements.
4. R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS).
5. MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.

**Please review the revised version of MOD-029 and then answer the following questions. You do not have to answer all questions. Enter All Comments in Simple Text Format.**

1. **The drafting team modified some requirements and associated measures in MOD-029 to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct.**

   Incorrect Requirement(s) or Measure(s):

2. **The drafting team has modified the Violation Risk Factors for MOD-029 to reflect industry concerns that they were too high. NERC's VRF definitions are listed below:**

   **High Risk Requirement**:
   (a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or
   (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

   **Medium Risk Requirement**:
   (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or
   (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

   **Lower Risk Requirement**: is administrative in nature and
   (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or
   (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

   **Are the current VRFs established correctly?**

   ☐ Yes

☐ No

**If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.**
Comments:

3. **The drafting team has modified the Violation Severity Levels for MOD-029 to reflect industry concerns that they were too "pass/fail" oriented. Are the current VSLs established correctly?**

   ☐ Yes
   ☐ No

   **If "No," please identify specific VSLs and suggest changes to the language.**
   Comments:

4. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-029.**

   Comments:

| | Individual or group. | Name | Organization | Group Name | Lead Contact | Contact Organization | Question 1 | Question 2 | Question 2 Comments | Question 3 | Question 3 Comments | Question 4 Comments |
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| | Group | | | WECC Market Interface Committee / Sub Commtt / ATC Task Force | W. Shannon Black | SMUD | Errata: MOD-29, R.1.1.1.2 and R.1.1.1.3, the word equivalent should be capitalized. MOD-29, M7 and M8 as drafted require the TSP to be "capable" of demonstration but do not require actual demonstration. The WECC Team suggests a minor rewrite to state, "The TSP shall demonstrate that..." This shifts the measurement from the TSP's mere capability to an actual performance. | Yes | | Yes | | The WECC Team notes that changing the modeling equivalence threshold within MOD-29 to match that of the other methodologies creates a seamless and equal application across all methodologies for all of NERC. |
| | Individual | Jack Cashin/Barry Green | EPSA | | | | Through this revision process, some of the MOD standards have included an explicit requirement for consistency between planning assumptions and modeling assumptions used in calculation of ATC. We believe this is appropriate and should be included in MOD 029. | | no comment | | no comment | no comment |
| | Individual | Jim Useldinger | Kansas City Power & Light | | | | The Transmission Service Provider should be added along with the TOP for these functions in all requirements | Yes | | Yes | | |

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| | Individual | Paul Rocha | CenterPoint Energy | | | | | | | | | The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a single control area. |
| | | | | WECC Market Interface | W. | | Errata: MOD-29, R.1.1.1.2 and R.1.1.1.3, the word equivalent should be capitalized. MOD-29, M7 and M8 as drafted require the TSP to be "capable" of demonstration but do not require actual | | | | | The WECC Team notes that changing the modeling equivalence threshold within MOD-29 to match |

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| | Group | | | Committee ATC Task Force | Shannon Black | SMUD | demonstration. The WECC Team suggests a minor rewrite to state, "The TSP shall demonstrate that..." This shifts the measurement from the TSP's mere capability to an actual performance. | Yes | | Yes | | that of the other methodologies creates a seamless and equal application across all methodologies for all of NERC. |
| | | | | | | | Requirement 1: I suggest modifying the requirement to state: "When calculating TTCs for ATC Paths, the Transmission Operator with ATC Path(s) shall use a Transmission model which satisfies the following requirements:" Requirement 2: I suggest modifying the requirement to state: "The Transmission Operator with ATC Path(s) shall use the following process to determine TTC:" Requirement 3: I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path." Requirement 4: I suggest modifying the requirement to state: "Within seven calendar days of the finalization of the study report, the Transmission Operator with ATC Path(s) shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the | | | | | I suggest mofifying the Applicability section to state" "4.1. Each Transmission Operator with ATC Path(s) that uses the Rated System Path |

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| | Individual | H. Steven Myers | ERCOT ISO | | | | assumptions used and steps taken in determining the current value for TTC for that ATC Path." Requirement 5: I suggest modifying the requirement to state: "When calculating ETC for firm Existing Transmission Commitments (ETCF) for a specified period for an ATC Path, the Transmission Service Provider with ATC Path (s) shall use the algorithm below:" Requirement 6: I suggest modifying the requirement to state: "When calculating ETC for non-firm Existing Transmission Commitments (ETCNF) for all time horizons for an ATC Path the Transmission Service Provider with ATC Path (s) shall use the following algorithm:" Requirement 7: I suggest modifying the requirement to state: "When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:" Requirement 8: I suggest modifying the requirement to state: "When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider with ATC Path (s) shall use the following algorithm:" | | | | | Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths." "4.2. Each Transmission Service Provider with ATC Path(s) that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths." |
| | | | | | | | NPCC Participating Members have the following comments on the Requirements | | | | | |

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| | Group | | | NPCC Reliability Standards Committee | Guy V. Zito | Northast Power Coordinating Council | and Measures: a. M1.1: The term “in its ATC calculations” is inappropriate and “its” should be removed. b. M7: This measure corresponds to R5, which stipulates the use of a specific algorithm. However, M7 provides the requirement for certain accuracy, which leads to the following questions i. Is R5 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm? ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M7) to determine if the algorithm and its settings have been properly used. iii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure. c. M8: Same comment on M7 also applies here for R6. d. The current wording on R2.4 and R2.5 can be viewed as conflicting and the language should be modified. R2.4 implies that ATC Paths can impact each other, hence the | Yes | | Yes | | |

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| | | | | | | | purpose for a nomogram. However, then R2.5 says that the TTC on an ATC Path cannot adversely impact the TTC of an existing path – that would imply that nomograms would never be required. In addition, R2.5 requires one specific approach to handling the condition where a ‘new’ study impacts an existing path. When, in reality, there are often contractual arrangements that would govern how that issue would be resolved where that resolution could be different than the approach defined in R2.5 and just as reliable. An example of that is when a ‘new’ path has an impact on an ‘old’ path, where ‘old path’ has no requests for service and the ‘new path’ will be in high demand. The following is our suggested language. The additional detail that we are suggesting be removed, the default resolution process, can be added to local procedures. 2.5 Transmission Operator shall identify when the TTC for the ATC Path being studied adversely impacts the TTC value of any existing path. The Transmission Operator shall include their resolution of this adverse impact in the study report for the ATC Path. | | | | | |
| | | | | | | | | | | | | The Applicability of this Standard |

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| | | | | | | | R1.1.1 possible English issue, Does the requirement allow that all radial lines be equivalents and that ALL facilities 161 kV and lower voltage may also be equivalents? | | | | | should be solely upon the TSP, the Transmission Operator should not be subject to this Standard. From the previous set of responses, it is the apparent belief of the SDT that the calculation of ATC is needed for reliability (response to AECI for example). We disagree. Considering that ATC is a mathematical amalgamation of forecasted system conditions (load, outages, generation dispatch, others' transactions, etc) compounded and adjusted by margins (TRM and CBM of own entity and other systems), using the calculated ATC to assess real or near real time transmission reliability would be – at best – unwise. Transmission Reliability can be assessed by monitoring specific and individual Facility loadings and/or other parameters, for example. The calculation of ATC and the value of resultant ATC is exactly for the purpose stated in the definition of ATC: “A measure |

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| | Individual | Thad Ness | AEP | | | | R.2.1.1 Was the intent that the 'base case' contain no loading above the respective normal rating, rather than the literal remove any overloaded line from the model? | | | | | of ... capability....for further commercial activity" – and note the definition does not infer ATC is a measure of reliability. Granted, ATC is calculated FROM reliability derived values and concepts (such as ratings, contingency analysis aspects, SOLs etc), BUT the resultant ATC values are not an assessment of transmission reliability – and therefore not a function for the Transmission Operators, but rather the Transmission Service Provider. In addition, the Purpose statement is unclear and perhaps nonsensical. Is the purpose "to increase consistency and reliability in the development of documentation...." or "to support analysis and system operation"? What entities' "short term use"? Suggestion: Purpose: To ensure consistency of calculation of those entities employing Rated System Path |

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| | | | | | | | | | | | | Methodology pursuant to MOD-001 R1. |
| | Group | | | Public Service Commission of South Carolina | Phil Riley | Public Service Commission of South Carolina | | Yes | | Yes | | |
| | Individual | Greg Rowland | Duke Energy Corporation | | | | R1.1 - Bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on TTC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders. R2.8 - Need to ensure that comparable information should be required in either the study report or the ATCID in MOD-028, MOD-029 and MOD-030. | Yes | | Yes | | |
| | Individual | Patrick Brown | PJM | | | | PJM does not have any specific comments. | Yes | PJM supports NERC's position to revise all Violation Risk Factors to have an assigned risk factor of “Lower.” A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting | PJM reiterates that while we will not choose the calculation methodologies used in MODs 28 and 29, these MODs will require modification to assure consistency with any revisions made to MOD 30. PJM is including specific comments for MOD 30 in Section VI of this |

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| | | | | | | | | | state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. | | of violations for a single event be eliminated. A single event shall not result in multiple violations –this language to be added to the standard. | document. PJM is not providing specific comments for MODs 28 and 29. |
| | Individual | Greg Ward / Darryl Curtis | Oncor Electric Delivery | | | | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). | Yes | | Yes | | This standard should not apply to ERCOT for the reason expressed in question 1. |
| | | | | | | | | | | | | BPA respectfully submits the following observations and suggestions: a. Including counterflows in the calculation of firm ATC is not appropriate |

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| | Group | | | Bonneville Power | Denise Koehn | Transmission Reliability Program | BPA does not believe any are incorrect. | Yes | | Yes | | because it could result in exceeding a TTC limit due to forced outage scenarios. An accurate estimation of counterflows cannot be assured and may result in over selling transmission. R7 should be modified to state that for firm ATC calculations counterflows shall always be zero. b. The Time Horizons listed for all requirements should include the “Long-term Planning” Horizon, as ATC is to be calculated beyond the seasonal window. c. Balancing Authorities may be appropriately identified as Applicable Entities in this MOD and request that the Standards Drafting Team provide an explanation as to why they are not listed. |
| | Individual | Richard Kafka | Pepco Holdings, Inc | | | | PHI supports the comments of PJM and will not submit duplicate comments | | | | | |
| | | | | | | | R2.5 reads: Verify that the TTC for the ATC Path being studied does not adversely impact the TTC value of any existing path. Do this by modeling the flow on the path | | | | | |

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| | Individual | Alice Druffel | Xcel Energy | | | | being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. We feel this requirement may be, in some cases, impractical to meet due to lack of resources (generation) to simultaneously load two paths (existing and new) to their TTC limits. We suggest that the 2nd sentence of this requirement be reworded something like this: "Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its highest achieveable TTC level, up to the existing path's TTC limit, with a realistic generation dispatch while at the same time honoring the reliaibility criteria outlined in R2.1". | Yes | | Yes | | |
| | | | | | | | 1. We have the following comments on the Requirements and Measures: a. R3: Should the “or” before “any system operating limits” be an “and” to go along with the requirement that stipulates picking the lesser value of two? Same change applies to M5, and VSLs for R3. b. M1.1: We do not understand the basis for this measure, in particular the form and format. They are not specified in the requirement. Further, | | | | We do not agree with the following VSLs: a. R1 has two subrequirements: R1.1 for modeling details and R1.2 for use of facility ratings provided by the | |

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| | Individual | Ron Falsetti | Ontario IESO | | | | the TOP does not calculate ATC; the term “in its ATC calculations” is inappropriate. c. M1.2: There seems to be an extra “1” after R1.1.1. d. M7: This measure corresponds to R5, which stipulates the use of a specific algorithm. However, M7 provides the requirement for certain accuracy, which leads to the following questions: i. Is R5 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm? ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M7) to determine if the algorithm and its settings have been properly used. ii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure. e. M8: Same comment on M7 also applies here for R6. f. The current wording on R2.4 and R2.5 can be viewed as conflicting and the language should be modified. R2.4 implies that ATC | No | Those requirements (at least R2 and R3) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in the TSP over-selling transmission services | No | owners. A total failure of R1 would be failing both subrequirements. On this basis, we agree with the Low and Moderate but do not agree with the Severe which if changed, can impact the High VSL as well. For Severe, we suggest to change the condition to “AND” instead of “OR”. And with this change, the High would thus be for “3 or more” in the first condition and “21 or more” in the second condition, and the same language apply to the conditions for Severe, or something along that line in terms of the threshold numbers. b. There are 2 measures developed for R2 – an M3 for R2.7 and an M4 for the rest of R2 including R2.8 (a report that shows the process detailed in R2.1 to R2.6 was followed). Yet the VSL only has one entry, which appears to treat R2 as a binary requirement. There are at least two issues with this lone VSL: 1. M3 and M4 become | None | |

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| | | | | | | Paths can impact each other, hence the purpose for a nomogram. However, then R2.5 says that the TTC on an ATC Path cannot adversely impact the TTC of an existing path – that would imply that nomograms would never be required. In addition, R2.5 requires one specific approach to handling the condition where a ‘new’ study impacts an existing path. When, in reality, there are often contractual arrangements that would govern how that issue would be resolved where that resolution could be different than the approach defined in R2.5 and just as reliable. An example of that is when a ‘new’ path has an impact on an ‘old’ path, where ‘old path’ has no requests for service and the ‘new path’ will be in high demand. The following is our suggested language. The additional detail that we are suggesting be removed, the default resolution process, can be added to local procedures. 2.5 Transmission Operator shall identify when the TTC for the ATC Path being studied adversely impacts the TTC value of any existing path. The Transmission Operator shall include their resolution of this adverse impact in the study report for the ATC Path. | | beyond the reliability bounds, risking the BES to unreliable operation. | | irrelevant 2. There is no provision for progressive (graded) VSLs for failing any of the subrequirements c. We suggest the SDT review the measures in conjunction with the VSLs for this requirement. At a minimum, the VSLs should be dependent on the number of subrequirements not met. If the SDT wishes to have a simple set of VSLs, it may consider eliminating M3 hence making all subrequirements binary to support a progressive (graded) VSL for the main requirement. d. R5: For these VSLs to be appropriate, please see our comments and suggestion for changes on M7 under Q1. e. R6: For these VSLs to be appropriate, please see our comments and suggestion for changes on M8 under Q1. | |

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| | Group | | | IRC Standards | Charles | Southwest | 1. We have the following comments on the Requirements and Measures: a. R3: Should the “or” before “any system operating limits” be an “and” to go along with the requirement that stipulates picking the lesser value of two? Same change applies to M5, and VSLs for R3. b. M1.1: We do not understand the basis for this measure, in particular the form and format. They are not specified in the requirement. Further, the TOP does not calculate ATC; the term “in its ATC calculations” is inappropriate. c. M1.2: There seems to be an extra “1” after R1.1.1. d. M7: This measure corresponds to R5, which stipulates the use of a specific algorithm. However, M7 provides the requirement for certain accuracy, which leads to the | No | No, those requirements (at least R2 and R3) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, | No | We do not agree with the following VSLs: a. R1: R1 has two subrequirements: R1.1 for modeling details and R1.2 for use of facility ratings provided by the owners. A total failure of R1 would be failing both subrequirements. On this basis, we agree with the Low and Moderate but do not agree with the Severe which if changed, can impact the High VSL as well. For Severe, we suggest to change the condition to “AND” instead of “OR”. And with this change, the High would thus be for “3 or more” in the first condition and “21 or more” in the second condition, and the same language apply to the conditions for Severe, or something along that line in terms of the threshold numbers. b. R2: There are 2 measures developed for R2 – an M3 for R2.7 and an M4 for the rest of R2 including R2.8 (a report that shows the process detailed in R2.1 to R2.6 was followed). Yet the | |

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| | | | | Review Committee | Yeung | Power Pool | following questions i. Is R5 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm? ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M7) to determine if the algorithm and its settings have been properly used. ii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure. e. M8: Same comment on M7 also applies here for R6. | | like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in risking the BES to unreliable operation. | | VSL only has one entry, which appears to treat R2 as a binary requirement. There are at least two issues with this lone VSL: i. M3 and M4 become irrelevant ii. There is no provision for progressive (graded) VSLs for failing any of the subrequirements We suggest the SDT review the measures in conjunction with the VSLs for this requirement. At a minimum, the VSLs should be dependent on the number of subrequirements not met. If the SDT wishes to have a simple set of VSLs, it may consider eliminating M3 hence making all subrequirements binary to support a progressive (graded) VSL for the main requirement. c. R5: For these VSLs to be appropriate, please see our comments and suggestion for changes on M7 under Q1. d. R6: For these VSLs to be appropriate, please see our comments and suggestion for changes on M8 under Q1. | |

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| | Individual | Rex McDaniel | Texas-New Mexico Power Company | | | | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). | Yes | | Yes | | This standard does not apply to ERCOT for the reason stated in Question 1. |
| | | | | | | | | | | | | The extent to which standard MOD-029 is able to attain consistency in calculating ATC in-part depends on the definitions of terms used in the formulas. Unfortunately, the definition of the word “commitment” is not specific enough to be useful. In fact, the same phrase (“existing transmission |

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| | Group | | | PPL Supply Group | Annette Bannon | PPL Generation | | | | | | commitment") is calculated differently in R5 than R6. For this reason, the term "ETC" should be dropped from standard MOD-029 and defined terms used. R6 defines PTP Non-Firm as including reserved capacity and should only include tagged or scheduled capacity. Capacity that is reserved but not scheduled should not affect NF ATC. It is also important that the same time periods be used to define the three time periods (scheduling horizon, operating horizon, and planning horizon) within an interconnect (i.e. the WECC) so that the same ATC algorithm is applied in all BA's across an interconnect for the same hour. |
| | | | | | | | PacifiCorp provided comments on March 12, 2008 related to the reference to counterflows in MOD-029, Rated System Path Methodology. In its comments, PacifiCorp relayed its concern that most transmission providers in the West, including PacifiCorp, using the Rated System Path Methodology do not | | | | | |

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| | | | | | | | use counterflows as defined in the formula for calculating increment firm ATC. The April 16, 2008 modified version of MOD-029 appears to address this concern by including language in M9 and M10 stating that: “Such documentation must show that only the variables allowed in R7 [R8 in M10] were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc.).” In order to ensure consistency with the above, PacifiCorp recommends the below modifications to the associated violation severity levels for R7 and R8 and the definition of Rated System Path Methodology. The recommended recognizes that future utility personnel and audit staff that do not have the benefit of participation in this process and record can clearly understand that counterflows and postbacks may be used as determined by the Transmission Provider, and the necessary documentation only applies to components used in the ATC | | | | | |

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| | Group | | | PacifiCorp | Shay LaBray | PacifiCorp | calculation. Specifically, 1. The violation severity level for R7 and R8 should be revised to read: "The Transmission Service Provider did not use all the elements defined and applicable in R7 when determining firm ATC, or used additional elements" or our earlier suggested revision "The Transmission Service Provider did not use all the elements defined in R7 and as specified in the Transmission Service Provider's Available Transfer Capability Implementation Document required in MOD-001, when determining firm ATC, or used additional elements." 2. In order to ensure consistency with the way counterflows are addressed, the definition of Rated System Path Methodology should include the words “as applicable” after the new inserted language “and postbacks and counterflows are added.” The revised language would read as follows: Rated System Path Methodology: The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission | | | | | |

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| | | | | | | | Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities. These changes ensure consistency and clarity of the standard that a utility is not required to apply counterflows to its firm ATC calculation. | | | | | |
| | | | | | | | | | | | | These comments are filed on behalf of City of Austin d/b/a Austin Energy to address proposed NERC 5 MOD Standards. Austin Energy is a municipally owned electric utility and a transmission service provider with the Electric Reliability Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with no explicit transmission services being sold. Current ERCOT market rules allow open transmission access to all loads and resources. ERCOT will continue to operate as a Single Balancing Authority under Nodal market |

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| | | | | | | | | | | | | design. Accordingly, as explained in more detail below, the NERC 5 MOD Standards should not be applied to ERCOT and transmission service providers within ERCOT under its current or proposed Nodal market design. Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. Applicable definitions: According to NERC Reliability Standards Glossary of Terms, Available Transfer Capability (ATC) is defined as: “A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and |

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| | | | | | | | | | | | | above already committed uses. It is defined as Total Transfer Capability (TTC) less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows”. TTC is defined as: the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions. CBM is defined as the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. TRM also is a component of ATC defined as: that amount of transmission transfer capability necessary to ensure that the interconnected |

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| | Group | | | Electric Service Delivery | Reza Ebrahimian | Austin Energy | | | | | | transmission network is secure under a reasonable range of uncertainties in system conditions. Comments: ERCOT is an interconnection and a region with no synchronous AC ties with any other interconnections. In July 2001, based on a deregulated Retail and restructured Wholesale Markets, the ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT market is designed such that there are no explicit transmission services being sold, hence, Available Transfer Capability (ATC) is not a measure used in a commercial activity within the ERCOT market. The current ERCOT market rules allow open transmission access to all eligible loads and resources without considering any specific Transmission Service Provider (TSP). Transmission facilities ratings are based upon individual branch |

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| | | | | | | | | | | | | element designs and in cases of dynamic ratings, ambient conditions are also considered. ERCOT has several DC ties and an asynchronous tie using a Variable Frequency Transformer (VFT); however, the associated interchange capabilities are planned and coordinated by the TSPs involved. The current ERCOT Zonal Market uses a flow based congestion management methodology to predict potential congestions in the Day Ahead and Adjustment Periods. During the operating period, generation shift factors are used to determine the dispatch needed to remain within the constrained limits. The local congestions are managed using full AC load flow analysis and unit specific redispatch. MOD-001-1 is entirely about methodology and calculation of ATC, therefore, this standard is not applicable to ERCOT. MOD-008-1 covers Transmission |

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| | | | | | | | | | | | | Reliability Margin (TRM) methodology calculation. Mathematically, ATC is defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin (CBM). Therefore, TRM also is not applicable to ERCOT. MOD-028-1 covers Area Interchange calculation Methodology. Since ERCOT is a single control area, Area Interchange calculation is not applicable. MOD-029-1 covers Rated System Path Methodology, which is used to calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT. MOD-030-1 covers Flowgate methodology calculation of ATC, and therefore, is not applicable to ERCOT. ERCOT is currently transitioning to a Nodal Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a Security Constrained Economic Dispatch (SCED) approach to |

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| | | | | | | | | | | | | dispatch individual generating units and manage congestion. In the Nodal Market, ERCOT will still operate as a Single Balancing Authority. This again will not use ATC methodology, and aforementioned standards are not applicable to ERCOT in its ensuing Nodal Market. Therefore, Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. |
| | | | | | | | The Rated System Path Methodology definition, like Area Interchange and Flowgate, includes the text: "Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive | | | | | |

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| | | | | | | | Available Transfer Capability." This text describes the derivation of ATC or AFC, and should not be part of a definition to differentiate between the AIM, RSP and Flowgate methods. R1.1.1 - I support allowing "Equivalent representation of radial lines and facilities 161 kV or below" but equivalences for elements that are included in the regionally definition of the BES should be explained in the ATCID. Additional detail is appropriate if eliminating an equivalence has a material impact on transfer capability. R1.1.3. Requires the Transmission Operator to “[Model] all generation Facilities larger than 20 MVA in the studied area.” The NERC Glossary defines Facility as: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). Thus this requirement refers to a single generator connected to the BES, rather than a station or project. R1.1.3 does not literally require modeling of wind and other renewable generation projects because each unit may only be 1.5 MW. Yet such projects are likely to be the modeled | | | | | | |

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| | Individual | Allen Mosher | American Public Power Association | | | | source for Interchange Transactions. Conversely, generation that is connected to non-BES subtransmission or distribution network facilities that is used to serve local load may not have a material impact on Rated System Path TTC and ATC. I suggest a hybrid definition that is consistent with the Compliance Registry Criteria but allows for additional detail as required: “Models all generation units larger than 20 MVA and generation projects larger than 75 MVA in the studied area that are directly connected to the Bulk Electric System. Modeling of additional generation Facilities shall be addressed in the ATCID.” R5 and R6 – Definition of “GF” Grandfathered Firm/Non-Firm Transmission Service – please delete “accepted by FERC” after “Safe Harbor Tariff.” FERC regulatory approval of a tariff for rate purposes is not relevant to what form of transmission service tariff a NERC TSP provides. Many U.S. utilities are not FERC jurisdictional for electric rate purposes. All Canadian TSPs are non-jurisdictional. R7 and R8 - Postbacks and counterflows: “Counterflows” should be a defined term. It is used in MOD-1, | Yes | | Yes | | Excellent work |

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| | | | | | | | MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-29-1 R7, for example, reads: “CounterflowsF are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.” This definition does not in any way describe what a counterflow is. “Postbacks” should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: “Postbacks[Firm][Non-Firm] are changes to firm [non-firm] ATC [AFC] due to a change in the amount of Firm [non-firm] Transmission Service reserved or scheduled for a period, as defined in Business Practices. Postbacks are generally a positive quantity.” Also, include Postbacks in the "e.g." list of factors in M9 and M10. | | | | | |
| | | | | | | | The NYISO has previously commented that it is critically important to it that the algorithm for calculating “Existing Transmission Commitments” (“ETC”) in MOD-029 (and -028) be interpreted | | | | | |

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| | | | | | | | flexibly. The NYISO’s existing ATC calculation procedure, which reflects the nature of its financial reservation system, and which has been accepted by the Commission, is to calculate firm and non-firm ATC as follows: ATC(Firm) = TTC – Transmission Flow Utilization(Firm) – TRM ATC(Non-Firm) = ATC(Firm) – Transmission Flow Utilization(Non-Firm) Where “Transmission Flow Utilization” represents the security constrained network powerflow solutions of the NYISO’s Security Constrained Unit Commitment software, with respect to the NYISO Day-Ahead Market, or its Real-Time Commitment and Real-Time Dispatch software with respect to the NYISO’s Real-Time Market. As the NYISO has explained in prior comments, it believes that the central role that Transmission Flow Utilization plays in its ATC/TTC calculations can be accommodated under proposed MOD-029 by accounting for it in the ETC calculation algorithms established under R5 and R6. Specifically, the SDT's proposed definition of the OS(F) variable appears to be broad enough to encompass Transmission Flow Utilization. The NYISO has previously requested that the | | | | | |

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| | Individual | Rick Gonzales | New York Independent System Operator | | | | SDT clarify or revise the OS(F) definition so that it would clearly allow the NYISO to account for Transmisison Flow Utilization in this way. The SDT has not yet responded. Accordingly, the NYISO requests that the the OS(F) definition under R5 be revised to read: OS(F) is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID, including security constrained network powerflow solutions produced by market software used by Transmisison Service Providers that administer FERC-approved organized markets. Similarly, the OS(F) definition under R6 should be revised to read: OS(F) is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID, including security constrained network powerflow solutions produced by market software used | | | | | | |

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| | | | | | | | by Transmisison Service Providers that administer FERC-approved organized markets. Making these revisions should have no impact on the vast majority of Transmission Service Providers, because they will neither administer FERC-approved organized markets nor use security constrained network powerflow solutions produced by market software in their ATC/TTC calculations. On the other hand, the revisions would permit the NYISO to come into compliance with NERC's proposed MOD standards without having to make fundamental changes to its FERC-approved market design or financial reservation transmission model. Order No. 890 was clear that it would not require fundamental changes to ISO/RTO market designs. This principle was recently upheld when FERC accepted the NYISO's Order No. 890 tariff compliance filing without requiring any changes to its financial reservation transmission model. The NYISO asks that the SDT make the requested revisions in order to elimiante any possibility of a conflict between the NYISO's FERC approved system and the NERC MOD standards. The NYISO recognizes that the definition of OS(F) | | | | | | |

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| | | | | | | | may already be broad enough to accommodate Transmission Flow Utilization. If the SDT does not make the requested revision the NYISO will take the position that it may describe its use of Transmission Flow Utilization in the ETC calculation within its ATCID. Nevertheless, because this issue is so important to the NYISO's future compliance with NERC's MOD standards the NYISO would strongly prefer that the issue be expressly addressed within the text of MOD-029 and (MOD-028). The NYISO may raise the issue at FERC if it is not addressed by NERC. | | | | | |
| | Individual | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | | | | | | | | | Brazos Electric believes that the concept of the Rated System Path Methodology is not applicable to a single-control area operation like ERCOT. To address this issue, the Applicability section could have a clarifying statement that only TOPs or TSPs that conduct area to area operations and hence have have responsibility for ATC Path(s) must have a Rated System Path Methodology to support analysis and system |

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RELIABILITY CORPORATION

**Consideration of Comments on Draft Standard — MOD-029 — Project 2006-07**

The ATC Standards Drafting Team thanks all commenters who submitted comments on the draft standard MOD-029-1 – Rated System Path methodology. This standard was posted for a 30-day public comment period from April 16, 2008 through May 15, 2008. The stakeholders were asked to provide feedback on the standard through a special electronic Standard Comment Form. There were 23 sets of comments, including comments from than 51 different people from approximately 30 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

There were some comments that led the drafting team to modify language to improve clarity, but none of the changes made by the drafting team changed the scope or intent of the requirements in the standard.

**Applicability**

- Several entities have continued to express concern regarding the applicability of the ATC, TRM, and CBM standards. While the drafting team has attempted to write the standards in ways that are flexible and allow for organizational diversity, we note that FERC Order 890 makes reference to the use of Variances. Entities with non-traditional physical transmission markets or that have alternative ATC methodologies that meet or exceed the NERC ATC standards may wish to consider requesting one or more Variances related to these standards.

- Several entities expressed concern regarding the responsibilities of the Transmission Operator. The SDT interprets the Functional Model as requiring the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. For those entities who believe the TSP to be the appropriate entity, we reiterate that options for delegation of this task exist.

- Some entities requested that some requirements be applicable to either the Transmission Operator or the Transmission Service Provider. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity “or” another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.

- Several entities expressed concern with ERCOT’s applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

**Requirements**

- R1.1.1.1 - Some entities questioned the use of the 161kV threshold, requesting either a lower threshold or a requirement to document reasons for using equivalences. The SDT suggested that if such requirements are desired, the commenter should submit a request for a regional standard.

- R1.1.3 - Some entities expressed concern that the current definition of what had to be modeled did not address collections of small generators that should be treated as a bulk power resource, such as wind farms. The SDT modified the standard to read "Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area. "

**Definitions**

- Some entities expressed concern that the definition of Rated System Path implied that counterflows must be used in the firm ATC calculation. The SDT added the words "as applicable" to the definition to clarify.

- Some entities expressed concerns with the definitions of Counterflows and Postbacks. The SDT does not believe that further definitions are necessary.

**Measures**

- M7 and M8 - Some entities expressed concern with the measures associated with the ETC calculation. The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation of the whether an entity is compliant. In response to concerns with data retention, the SDT has modified the data retention and the measure. The data retention now states that data to demonstrate compliance with hourly ETC calculations must be retained for 14 days, for daily calculations must be retained for 30 days, and for monthly calculations must be retained for 60 days. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used.

**Compliance**

- Most commenters supported the setting of the Violation Risk Factors in the standard to "Lower." Two entities commented that requirement R2 and R3 should be higher. The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R2 and R3 do not directly affect the electrical state or the capability of the bulk power system.

- Some suggestions were made to change specific VSLs or measures and make them more graded. The SDT modified VSLs for R2, but did not modify the other measures or VSLs.

- Some commenter's expressed concern with potential for multiple violations of the standard due to a single event. The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.

- The drafting team provided a summary of the use of time horizons to address some comments.

**Concepts**

- One entity expressed concern that in some instances it may not be possible to stress both the existing and the new path to their limit simultaneously due to lack of resources. The SDT responded that when that occurs one method of dealing with the situation is to create a nomogram.

- The NERC RTOSDT expressed concern that the standard does not refer to Planning an operating limits. The SDT directed the RTOSDT to the specific areas in the methodology standard where such reference rare made.

**Variances**

The SDT believes it may be helpful to the industry to review the process for Variances. The Variance process can work either concurrent with or independent of the development of a standard. Because the drafting team working on a particular standard is likely to already have the necessary expertise to participate in the development of the Variance, concurrent development is generally more efficient. However, this may not always be practical; in this case, standards drafting may proceed, and even complete, prior to the development and approval of Variances. In this case, entities should seek to develop those Variances and seek their approval prior to the effective date of the standard. An entity is not exempt from meeting the requirements of the standard if the effective date has passed and that entity is in the process of developing a Variance.

The NERC process allows for three different types of variances:

- An Entity Variance
- A Regional Variance less than an Interconnection
- A Regional Variance on Interconnection-Wide basis

The NERC Rules of Procedure describe an Entity Variance as follows:

> Entity Variance — Any variance from a NERC reliability standard that is proposed to apply to one entity or a subset of entities within a limited portion of a regional entity, such as a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users, shall be approved through the regular standards development process defined in the NERC Reliability Standards Development Procedure and shall be made part of the applicable NERC reliability standard.

Entities seeking an Entity Variance should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requester is addressing the reliability goals of the standard. The ballot body is comprised of any member of the Registered Ballot Body that is interested and registers to join the ballot pool. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe a Regional Variance Less Than an Interconnection as follows:

> Any regional variance from a NERC reliability standard that is proposed to apply for a regional entity, but not for an interconnection, shall be approved through the NERC Reliability Standards Development Procedure, except that only members of the registered ballot body located in the affected interconnection shall be permitted to vote; and the variance shall be made part of the applicable NERC reliability standard.

Entities seeking a Regional Variance Less Than an Interconnection should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requestor is addressing the reliability goals of the standard. The ballot body is comprised of any interested entities that that have registered with NERC and is a user, owner, or operator of facilities located within the interconnection in which the region requesting the Variance is located. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe an Regional Variance on an Interconnection-wide Basis as follows:

> An interconnection-wide regional variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the NERC reliability standard. NERC shall rebuttably presume that a regional variance from a NERC reliability standard that is developed, in accordance with a procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Entities seeking a Regional Variance on an Interconnection-wide Basis should draft that Variance using the regional standards development process described in the region's delegation agreement. In that Variance, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Once approved through the regional standards development process, the Variance should be brought to NERC for filing with the appropriate regulatory authorities.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving these standards forward to posting for pre-ballot review.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standard can be viewed in their original format at:

[http://www.nerc.com/~filez/standards/MOD-V0-Revision.html](http://www.nerc.com/~filez/standards/MOD-V0-Revision.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Thad Ness | AEP | x | | x | | x | x | | | | |
| 2. | Anita Lee (G3) | AESO | | x | | | | | | | | |
| 3. | Allen Mosher | American Public Power Association | x | | | x | | x | | | | |
| 4. | Jerry Smith (G2) | APS | x | | | | | | | | | x |
| 5. | Reza Ebrihimian | Austin Energy | x | | | | | | | | | |
| 6. | Denise Koehn (G6) | Bonneville Power Administration | x | | x | | x | x | | | | |
| 7. | Mike Viles (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 8. | Abbey Nulph (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 9. | Don Watkins (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 10. | Patrick Roechelle (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 11. | Kammy Rogers-Holiday (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 12. | Robin Chung (G6) | Bonneville Power Administration | | | x | | x | x | | | | |
| 13. | Rebecca Berdahl (G6) | Bonneville Power Administration | | | x | | | | | | | |
| 14. | Susan Millar (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 15. | Todd Miller (G6) | Bonneville Power Administration | | | x | | x | x | | | | |
| 16. | Elizabeth Loebach (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 17. | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | x | | | | x | | | | | |
| 18. | Dave Lunceford (G2) | California ISO | | x | | | | | | | | x |
| 19. | Brent Kingsford (G3) | California ISO | | x | | | | | | | | |
| 20. | Paul Rocha | CenterPoint Energy | x | | | | | | | | | |
| 21. | Greg Rowland | Duke Energy Corporation | x | | x | | x | x | | | | |
| 22. | Jack Cashin/Barry | EPSA | | | | | x | x | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | Green | | | | | | | | | | | |
| 23. | H. Steven Myers (G3) (G5) (I) | ERCOT ISO | | x | | | | | | | | |
| 24. | David Kiguel (G4) | Hydro One Networks | x | | x | | | | | | | |
| 25. | Roger Champagne (G4) | Hydro Quebec TransEnergie | x | x | | | | | | | | |
| 26. | Ron Falsetti (G3) (I) | IESO | | x | | | | | | | | |
| 27. | Matt Goldberg (G3) | ISO-New England | | x | | | | | | | | |
| 28. | Kathleen Goodman (G4) | ISO-New England | | x | | | | | | | | |
| 29. | Jim Useldinger | Kansas City Power & Light | x | | | | | | | | | |
| 30. | Bill Phillips (G3) | MISO | | x | | | | | | | | |
| 31. | Rick Gonzales | New York Independent System Operator | | x | | | | | | | | |
| 32. | Greg Campoli (G4) | New York ISO | | x | | | | | | | | |
| 33. | Ralph Rufrano (G4) | New York Power Authority | x | | | x | x | x | | | x | |
| 34. | Al Adamson (G4) | NYSRC | | | | | | | | | | |
| 35. | Rick White (G4) | Northeast Utilities | x | | | x | | | | | | |
| 36. | Guy V. Zito (G4) | NPCC | | | | | | | | | | x |
| 37. | Jim Castle (G3) | NYISO | | x | | | | | | | | |
| 38. | Greg Ward / Darryl Curtis | Oncor Electric Delivery | x | | | | | | | | | |
| 39. | Shay LaBray | PacifiCorp | x | | x | | | | | | | |
| 40. | Richard Kafka | Pepco Holdings, Inc. | x | | x | | x | x | | | | |
| 41. | Patrick Brown (G3) (I) | PJM | | x | | | | | | | | |
| 42. | John Cummings (G4) | PPL EnergyPlus | | | | | | x | | | | |
| 43. | Jon Williamson (G4) | PPL EnergyPlus | | | | | | x | | | | |
| 44. | Mark Hemibach (G4) | PPL Generation/PPL EnergyPlus | | | | | x | x | | | | |
| 45. | Annette Bannon (G4) | PPL Supply Group | x | | x | | x | x | | | | |
| 46. | Phil Riley | Public Service Commission of South Carolina | | | | | | | | | x | |
| 47. | W. Shannon Black (G2) | Sacramento Municipal Utility District | | | x | | | | | | | |
| 48. | Charles Young (G3) | Southwest Power Pool | | x | | | | | | | | |
| 49. | Chuck Falls (G2) | SRP | x | | | | | | | | | x |
| 50. | Rex McDaniel | Texas-New Mexico Power Company | x | | | | | | | | | |
| 51. | Alice Druffel | Xcel Energy | x | | x | | x | x | | | | |

I — Individual
G2 — WECC Market Interface Committee / Sub Commtt / ATC Task Force
G3 — ISO RTO Council/Standards Review Committee (SRC)
G4 — NPCC Regional Standards Committee
G6 — BPA

1. The drafting team modified some requirements and associated measures in MOD-029 to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct. Incorrect Requirement(s) or Measure(s):?

**Summary Consideration:**
Some entities requested that either the Transmission operator or the Transmission Service Provider be applicable. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

Some entities expressed concern with the measures associated with the ETC calculation. The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation of the whether an entity is compliant. In response to concerns with data retention, the SDT has modified the data retention and the measure. The data retention now states that data to demonstrate compliance with hourly ETC calculations must be retained for 14 days, for daily calculations must be retained for 30 days, and for monthly calculations must be retained for 60 days. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used.

Some entities questioned the use of the 161kV threshold, requesting either a lower threshold or a requirement to document reasons for using equivalences. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. Requirements for Data Exchange in MOD-001 already address sharing of models to support reliability objectives; to the extent a reliability entity has concerns regarding the use of equivalences within the model, the SDT encourages those entities to work directly with each other. Disclosure of this information to Transmission Customers should be addressed through the use of the NAESB process.

One entity expressed concern that in some instances it may not be possible to stress both the existing and the new path to their limit simultaneously due to lack of resources. The SDT responded that when that occurs one method of dealing with the situation is to create a nomogram.

Some entities expressed concern that the definition of Rated System Path implied that counterflows must be used in the firm ATC calculation. The SDT added the words "as applicable" to the definition to clarify.

Some entities expressed concern that the current definition of what had to be modeled did not address collections of small generators that should be treated as a bulk power resource, such as wind farms. The SDT modified the standard to read "Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area. "

Some entities expressed concerns with the definitions of Counterflows and Postbacks. The SDT does not believe that further definitions are necessary.

| **Organization** | **Question 1 - Incorrect Requirement(s) or Measure(s):** |
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| SMUD | Errata: MOD-29, R.1.1.1.2 and R.1.1.1.3, the word equivalent should be capitalized.<br>MOD-29, M7 and M8 as drafted require the TSP to be "capable" of demonstration but do not require actual demonstration. The WECC Team suggests a minor rewrite to state, "The TSP shall demonstrate that..." This shifts the measurement from the TSP's mere capability to an actual performance. |
| **Response:** Thank you for your comments. The SDT has accepted your suggestions. The word equivalent has been capitalized in MOD-29 R.1.1.1.2 and R.1.1.1.3.<br>The phrase "The TSP shall demonstrate that..." replaces "The TSP must be capable of demonstrating" in both M7 and M8 of MOD-29. | |
| EPSA | Through this revision process, some of the MOD standards have included an explicit requirement for consistency between planning assumptions and modeling assumptions used in calculation of ATC. We believe this is appropriate and should be included in MOD 029. |
| **Response:** While not stated explicitly, the SDT believes that the concerns of EPSA are addressed in R6 and R7 of MOD-001 and R1.1 of MOD 29. The SDT attempted to consider the intent of the Order in its review of this requirement. It seems clear, from both a reading of the Order and from comments submitted to the SDT, that FERC's intent is to ensure that service is not sold on a more conservative basis than the system has been planned for. Accordingly, the SDT modified this requirement to more closely align with this goal. | |
| Kansas City Power & Light | The Transmission Service Provider should be added along with the TOP for these functions in all requirements |
| Response: Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. | |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| ERCOT ISO | Requirement 1:I suggest modifying the requirement to state: "When calculating TTCs for ATC Paths, the Transmission Operator with ATC Path(s) shall use a Transmission model which satisfies the following requirements<br><br>"Requirement 2:I suggest modifying the requirement to state: "The Transmission Operator with ATC Path(s) shall use the following process to determine TTC:<br><br>"Requirement 3:I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path.<br><br>"Requirement 4:I suggest modifying the requirement to state: "Within seven calendar days of the finalization of the study report, the Transmission Operator with ATC Path(s) shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path<br><br>"Requirement 5:I suggest modifying the requirement to state: "When calculating ETC for firm Existing Transmission Commitments (ETCF) for a specified period for an ATC Path, the Transmission Service Provider with ATC Path(s) shall use the algorithm below:<br><br>"Requirement 6:I suggest modifying the requirement to state: "When calculating ETC for non-firm Existing Transmission Commitments (ETCNF) for all time horizons for an ATC Path the Transmission Service Provider with ATC Path(s) shall use the following algorithm:<br><br>"Requirement 7:I suggest modifying the requirement to state: "When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:<br><br>"Requirement 8:I suggest modifying the requirement to state: "When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:" |

**Response:** The drafting team has reviewed your comments and has not modified the standard for the following reason. This standard is intended to apply to all entities that have chosen to implement the Rated System Path methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.

Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| Northeast Power Coordinating Council | NPCC Participating Members have the following comments on the Requirements and Measures: a. M1.1: The term "in its ATC calculations" is inappropriate and "its" should be removed.<br>**Response:** The SDT agrees and has deleted "used in its ATC calculation" from M1.1.<br><br>b. M7: This measure corresponds to R5, which stipulates the use of a specific algorithm. However, M7 provides the requirement for certain accuracy, which leads to the following questions<br>i. Is R5 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm?<br><br>ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M7) to determine if the algorithm and its settings have been properly used .<br><br>iii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure.<br>**Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to its documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used.<br><br>c. M8: Same comment on M7 also applies here for R6.<br>**Response:** Please see previous response.<br><br>d. The current wording on R2.4 and R2.5 can be viewed as conflicting and the language should be modified. R2.4 implies that ATC Paths can impact each other, hence the purpose for a nomogram. However, then R2.5 says that the TTC on an ATC Path cannot adversely impact the TTC of an existing path — that would imply that nomograms would never be required. In addition, R2.5 requires one specific approach to handling the condition where a “new” study impacts an existing path. When, in reality, there are often contractual arrangements that would govern how that issue would be resolved where that resolution could be different than the approach defined in R2.5 and just as reliable. An example of that is when a “new” path has an impact on an “old” path, where “old path” has no requests for service and the “new path” will be in high demand. The following is our suggested language. The additional detail that we are suggesting be removed, the default resolution process, can be added to local procedures. 2.5 Transmission Operator shall identify when the TTC for the ATC Path being studied adversely impacts the TTC value of any existing path. The Transmission Operator shall include their resolution of this adverse impact in the study report for the ATC Path.<br>**Response:** The SDT agrees and has modified R2.5 to address this. |
| AEP | R1.1.1 possible English issue, Does the requirement allow that all radial lines be equivalents and that ALL facilities 161 kV and lower voltage may also be equivalents?<br>**Response:** R1.1.1 does *allow* for *ALL* radial lines and facilities 161 kV and lower voltage to be equivalenced, however it does not *require* the equivalence of these.<br><br>R.2.1.1 Was the intent that the “base case” contain no loading above the respective normal rating, rather than the literal remove any overloaded line from the model?<br>**Response:** To address your concerns the SDT has reworded R2.1.1 to read:<br>“ When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating. “ |
| Duke Energy Corporation | R1.1 – Bulk electric system facilities 161kV and below may have significant network response. Since these facilities |

| **Organization** | **Question 1 - Incorrect Requirement(s) or Measure(s):** |
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| | may have significant impact on TTC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders.<br>**Response:** The Drafting Team notes that the language of R1.1 allows detailed modeling of 161 kV and below; the language does not require it. Requirements for Data Exchange in MOD-001 already address sharing of models to support reliability objectives; to the extent a reliability entity has concerns regarding the use of equivalences within the model, the SDT encourages those entities to work directly with each other. Disclosure of this information to Transmission Customers should be addressed through the use of the NAESB process.<br><br>R2.8 – Need to ensure that comparable information should be required in either the study report or the ATCID in MOD-028, MOD-029 and MOD-030.<br>**Response:** The MOD-028 and MOD-030 standards have requirements for information to be located in the ATCID. MOD-029 has requirements for the comparable information to be included in the resulting study report. The SDT has reviewed and confirmed that the requirements are equivalent across the methodologies. |
| Oncor Electric Delivery | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Rated System Path methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| Xcel Energy | R2.5 reads: Verify that the TTC for the ATC Path being studied does not adversely impact the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | R2.1.We feel this requirement may be, in some cases, impractical to meet due to lack of resources (generation) to simultaneously load two paths (existing and new) to their TTC limits. We suggest that the 2nd sentence of this requirement be reworded something like this: "Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its highest achieveable TTC level, up to the existing path's TTC limit, with a realistic generation dispatch while at the same time honoring the reliability criteria outlined in R2.1".<br>**Response:** The SDT agrees that in some instances it may not be possible to stress both the existing and the new path to their limit simultaneously due to lack of resources. When that occurs one method of dealing with the situation is to create a nomogram which quantifies the simultaneous interaction between the two paths as suggested in R2.4. This is no different from the case where the new path cannot be modeled at its proposed limit simultaneously with the existing path at its limit due to violation of a reliability criteria (e.g. thermal limit, voltage limit or stability limit). In the case where a lack of resources is the reason for the simultaneous interaction the new path would be considered “flow limited” (i.e. not able to simulate the desired flow) rather than “reliability criteria limited.” The SDT does not believe there is a need to change the wording of requirement R2.5. |
| Ontario IESO | 1. We have the following comments on the Requirements and Measures:<br><br>a. R3: Should the “or” before “any system operating limits” be an “and” to go along with the requirement that stipulates picking the lesser value of two? Same change applies to M5, and VSLs for R3.<br>**Response:** The SDT believe that replacing the “or” with “and” does not add clarity to the requirement, and has left R3 as written.<br><br>b. M1.1: We do not understand the basis for this measure, in particular the form and format. They are not specified in the requirement.<br>**Response:** R1 calls for and specifies the parameters of the model used by the TOP to calculate TTC. M1. calls for production of the model used. M1.1. further limits the mandate to produce the model. M1.1 prohibits the auditing entity from requiring the TOP translate or convert its model from one “form and format” to any another specified by the auditing entity. Restated: If the model used is created in “Software Package 1” whereas the auditing entity’s hardware /software can only read “Software Package 2”, the auditing entity cannot mandate an upgrade to “Software Package 2” nor can it require alteration of the model to any other “form and format” from that in which the model was originally created.<br><br>Further, the TOP does not calculate ATC; the term ?in its ATC calculations? is inappropriate.<br>**Response:** The SDT agrees and has reworded as follows: |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | "Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1."<br><br>c. M1.2: There seems to be an extra "1" after R1.1.1.<br>**Response:** The SDT agrees and has deleted the extra "1".<br><br>d. M7: This measure corresponds to R5, which stipulates the use of a specific algorithm. However, M7 provides the requirement for certain accuracy, which leads to the following questions :<br>i. Is R5 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm? ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M7) to determine if the algorithm and its settings have been properly used. ii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure.<br><br>e. M8: Same comment on M7 also applies here for R6.f.<br>**Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used.<br><br>The current wording on R2.4 and R2.5 can be viewed as conflicting and the language should be modified. R2.4 |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | implies that ATC Paths can impact each other, hence the purpose for a nomogram.  However, then R2.5 says that the TTC on an ATC Path cannot adversely impact the TTC of an existing path — that would imply that nomograms would never be required.  In addition, R2.5 requires one specific approach to handling the condition where a "new" study impacts an existing path. When, in reality, there are often contractual arrangements that would govern how that issue would be resolved where that resolution could be different than the approach defined in R2.5 and just as reliable. An example of that is when a "new" path has an impact on an "old" path, where "old path" has no requests for service and the ?new path? will be in high demand. The following is our suggested language.  The additional detail that we are suggesting be removed, the default resolution process, can be added to local procedures. 2.5 Transmission Operator shall identify when the TTC for the ATC Path being studied adversely impacts the TTC value of any existing path.  The Transmission Operator shall include their resolution of this adverse impact in the study report for the ATC Path.<br>**Response:** The SDT agrees and has modified R2.5 to reflect this. |
| Southwest Power Pool | 1. We have the following comments on the Requirements and Measures: a. R3: Should the "or" before "any system operating limits" be an "and" to go along with the requirement that stipulates picking the lesser value of two? Same change applies to M5, and VSLs for R3.<br>**Response:** The SDT believe that replacing the "or" with "and" does not add clarity to the requirement, and has left R3 as written.<br><br>b. M1.1: We do not understand the basis for this measure, in particular the form and format. They are not specified in the requirement.<br>**Response:** R1 calls for and specifies the parameters of the model used by the TOP to calculate TTC.  M1. Calls for production of the model used.  M1.1. further limits the mandate to produce the model.  M1.1 prohibits the auditing entity from requiring the TOP translate or convert its model from one "form and format" to any another specified by the auditing entity.  Restated:  If the model used is created in "Software Package 1" whereas the auditing entity's hardware /software can only read "Software Package 2", the auditing entity cannot mandate an upgrade to "Software Package 2" nor can it require alteration of the model to any other "form and format" from that in which the model was originally created.<br><br>Further, the TOP does not calculate ATC; the term "in its ATC calculations" is inappropriate.<br>**Response:** The SDT agrees and has reworded as follows:<br><br>"Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1." |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | c. M1.2: There seems to be an extra “1” after R1.1.1.<br>**Response:** The SDT agrees and has deleted the extra “1”.<br><br>d. M7: This measure corresponds to R5, which stipulates the use of a specific algorithm. However, M7 provides the requirement for certain accuracy, which leads to the following questions<br>i. Is R5 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm?<br>ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M7) to determine if the algorithm and its settings have been properly used .<br>ii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure.<br><br>e. M8: Same comment on M7 also applies here for R6.<br>**Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity’s processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a “pass/fail” VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity’s process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how “repeatable” the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used. |
| Texas-New Mexico Power Company | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s).<br>**Response:** This standard is intended to apply to all entities that have chosen to implement the Rated System Path methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* |
| PacifiCorp | PacifiCorp provided comments on March 12, 2008 related to the reference to counterflows in MOD-029, Rated System Path Methodology. In its comments, PacifiCorp relayed its concern that most transmission providers in the West, including PacifiCorp, using the Rated System Path Methodology do not use counterflows as defined in the formula for calculating increment firm ATC. The April 16, 2008 modified version of MOD-029 appears to address this concern by including language in M9 and M10 stating that: –Such documentation must show that only the variables allowed in R7 [R8 in M10] were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc.).<br><br>–In order to ensure consistency with the above, PacifiCorp recommends the below modifications to the associated violation severity levels for R7 and R8 and the definition of Rated System Path Methodology. The recommended recognizes that future utility personnel and audit staff that do not have the benefit of participation in this process and record can clearly understand that counterflows and postbacks may be used as determined by the Transmission Provider, and the necessary documentation only applies to components used in the ATC calculation. |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | Specifically, 1. The violation severity level for R7 and R8 should be revised to read: "The Transmission Service Provider did not use all the elements defined and applicable in R7 when determining firm ATC, or used additional elements" or our earlier suggested revision "The Transmission Service Provider did not use all the elements defined in R7 and as specified in the Transmission Service Provider's Available Transfer Capability Implementation Document required in MOD-001, when determining firm ATC, or used additional elements."<br>**Response:** The SDT believes the concerns with counter flows are addressed in M9 and M10 as they are currently written.<br><br>In order to ensure consistency with the way counterflows are addressed, the definition of Rated System Path Methodology should include the words "as applicable" after the new inserted language ?and postbacks and counterflows are added.? The revised language would read as follows: Rated System Path Methodology: The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities. These changes ensure consistency and clarity of the standard that a utility is not required to apply counterflows to its firm ATC calculation.<br><br>Response: The SDT agrees and has added "as applicable" to the definition. |
| American Public Power Association | The Rated System Path Methodology definition, like Area Interchange and Flowgate, includes the text: "Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability." This text describes the derivation of ATC or AFC, and should not be part of a definition to differentiate between the AIM, RSP and Flowgate methods.<br>**Response:** The derivation of ATC is part of the Rated System Path Methodology, it is not identical in all three methods and it is appropriate to be included.<br><br>R1.1.1 - I support allowing "Equivalent representation of radial lines and facilities 161 kV or below" but equivalences for elements that are included in the regionally definition of the BES should be explained in the ATCID. Additional detail is appropriate if eliminating an equivalence has a material impact on transfer capability. |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | **Response:** The Drafting Team notes that the language of R2.1 allows detailed modeling of 161 kV and below; the language does not require it. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. Requirements for Data Exchange in MOD-001 already address sharing of models to support reliability objectives; to the extent a reliability entity has concerns regarding the use of equivalences within the model, the SDT encourages those entities to work directly with each other. Disclosure of this information to Transmission Customers should be addressed through the use of the NAESB process.<br><br>R1.1.3. Requires the Transmission Operator to ? [Model] all generation Facilities larger than 20 MVA in the studied area.? The NERC Glossary defines Facility as: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). Thus this requirement refers to a single generator connected to the BES, rather than a station or project.R1.1.3 does not literally require modeling of wind and other renewable generation projects because each unit may only be 1.5 MW. Yet such projects are likely to be the modeled source for Interchange Transactions. Conversely, generation that is connected to non-BES subtransmission or distribution network facilities that is used to serve local load may not have a material impact on Rated System Path TTC and ATC. I suggest a hybrid definition that is consistent with the Compliance Registry Criteria but allows for additional detail as required: –Models all generation units larger than 20 MVA and generation projects larger than 75 MVA in the studied area that are directly connected to the Bulk Electric System. Modeling of additional generation Facilities shall be addressed in the ATCID.<br>**Response**: We agree with your comment and acknowledge the concerns. 75 MVA may be good for compliance registration; however for TTC the 20 MVA threshold is more accurate without being over prescriptive. We have modified the requirement to read: “Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area. “<br><br>”R5 and R6 “Definition of “GF” Grandfathered Firm/Non-Firm Transmission Service — please delete “accepted by FERC” after “Safe Harbor Tariff.” FERC regulatory approval of a tariff for rate purposes is not relevant to what form of transmission service tariff a NERC TSP provides. Many U.S. utilities are not FERC jurisdictional for electric rate purposes. All Canadian TSPs are non-jurisdictional.<br>**Response**: The SDT agrees and has modified R5 and R6 per APPA’s suggestion.<br><br>R7 and R8 — Postbacks and counterflows: “Counterflows” should be a defined term. It is used in MOD-1, MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-29-1 R7, for example, reads: “Counterflows” are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID. This definition does not in any way describe what a |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | counterflow is. “Postbacks” should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: – Postbacks [Firm][Non-Firm] are changes to firm [non-firm] ATC [AFC] due to a change in the amount of Firm [non-firm] Transmission Service reserved or scheduled for a period, as defined in Business Practices. Postbacks are generally a positive quantity. Also, include Postbacks in the "e.g." list of factors in M9 and M10.<br>**Response:** The SDT has reviewed the standards, and finds that the Postbacks and counterflows definitions, the requirements for the ATCID, and the requirements and measures for calculating ATC in the methodologies address this sufficiently. MOD-001 indicates in the definition that Postbacks are defined by business practices, while the individual methodology standards indicate that Postbacks are “changes to firm (non-firm) ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.” Counterflows is an industry term, and the manner in which it applies to these standards is described in the methodologies (“adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID”), as well as in MOD-001 R3.2. |
| New York Independent System Operator | The NYISO has previously commented that it is critically important to it that the algorithm for calculating “Existing Transmission Commitments” (“ETC”) in MOD-029 (and -028) be interpreted flexibly. The NYISO’s existing ATC calculation procedure, which reflects the nature of its financial reservation system, and which has been accepted by the Commission, is to calculate firm and non-firm ATC as follows :ATC(Firm) = TTC ? Transmission Flow Utilization (Firm) — TRMATC (Non-Firm) = ATC(Firm) — Transmission Flow Utilization (Non-Firm) Where “Transmission Flow Utilization” represents the security constrained network powerflow solutions of the NYISO’s Security Constrained Unit Commitment software, with respect to the NYISO Day-Ahead Market, or its Real-Time Commitment and Real-Time Dispatch software with respect to the NYISO’s Real-Time Market. As the NYISO has explained in prior comments, it believes that the central role that Transmission Flow Utilization plays in its ATC/TTC calculations can be accommodated under proposed MOD-029 by accounting for it in the ETC calculation algorithms established under R5 and R6.<br>Specifically, the SDT's proposed definition of the OS (F) variable appears to be broad enough to encompass Transmission Flow Utilization. The NYISO has previously requested that the SDT clarify or revise the OS (F) definition so that it would clearly allow the NYISO to account for Transmission Flow Utilization in this way. The SDT has not yet responded. Accordingly, the NYISO requests that the OS(F) definition under R5 be revised to read: OS (F) is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID, including security constrained network powerflow solutions produced by market software used by Transmission Service Providers that administer FERC-approved organized markets. Similarly, the OS(F) definition under R6 should be revised to read: OS(F) is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as |

| Organization | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | specified in the ATCID, including security constrained network powerflow solutions produced by market software used by Transmission Service Providers that administer FERC-approved organized markets Making these revisions should have no impact on the vast majority of Transmission Service Providers, because they will neither administer FERC-approved organized markets nor use security constrained network powerflow solutions produced by market software in their ATC/TTC calculations. On the other hand, the revisions would permit the NYISO to come into compliance with NERC's proposed MOD standards without having to make fundamental changes to its FERC-approved market design or financial reservation transmission model. Order No. 890 was clear that it would not require fundamental changes to ISO/RTO market designs. This principle was recently upheld when FERC accepted the NYISO's Order No. 890 tariff compliance filing without requiring any changes to its financial reservation transmission model. The NYISO asks that the SDT make the requested revisions in order to eliminate any possibility of a conflict between the NYISO's FERC approved system and the NERC MOD standards. The NYISO recognizes that the definition of OS (F) may already be broad enough to accommodate Transmission Flow Utilization. If the SDT does not make the requested revision the NYISO will take the position that it may describe its use of Transmission Flow Utilization in the ETC calculation within its ATCID. Nevertheless, because this issue is so important to the NYISO's future compliance with NERC's MOD standards the NYISO would strongly prefer that the issue be expressly addressed within the text of MOD-029 and (MOD-028). The NYISO may raise the issue at FERC if it is not addressed by NERC.<br>**Response:** As NYISO has noted in their comment on MOD-029, the current wording of the OS term is broad enough to cover the NYISO market condition described. In addition, there is a NERC process by which NYISO can request a formal interpretation |
| PJM | PJM does not have any specific comments. |
| Pepco Holdings, Inc | PHI supports the comments of PJM and will not submit duplicate comments |
| **Response:** PJM did not provide comments. | |
| Transmission Reliability Program | BPA does not believe any are incorrect. |
| **Response:** Thank you for your supportive comment. | |

2. The drafting team has modified the Violation Risk Factors for MOD-029 to reflect industry concerns that they were too high. NERC's VRF definitions are listed below. Are the current VRFs established correctly? If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification?

High Risk Requirement:

(a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement:

(a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement: is administrative in nature and

(a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or

(b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

**Summary Consideration:**

Most commenters supported the change to Lower VRFs.

Two entities commented that requirement R2 and R3 should be higher. The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R2 and R3 do not directly affect the electrical state or the capability of the bulk power system.

| Organization | Question 2: | Question 2 Comments: |
|---|---|---|
| Ontario IESO | No | Those requirements (at least R2 and R3) that hold the TOP responsible for establishing TTCs should be |

| Organization | Question 2: | Question 2 Comments: |
|---|---|---|
| | | assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable operation. |
| **Response:** The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R2 and R3 do not directly affect the electrical state or the capability of the bulk power system. | | |
| Southwest Power Pool | No | No, those requirements (at least R2 and R3) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in risking the BES to unreliable operation. |
| **Response:** The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R2 and R3 do not directly affect the electrical state or the capability of the bulk power system. | | |
| PJM | Yes | PJM supports NERC's position to revise all Violation Risk Factors to have an assigned risk factor of ?Lower.? A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. |
| **Response:** Thank you for your supportive comment. | | |
| SMUD | Yes | |
| Kansas City Power & Light | Yes | |
| SMUD | Yes | |
| Northast Power Coordinating Council | Yes | |
| Public Service Commission of South Carolina | Yes | |
| Duke Energy Corporation | Yes | |
| Oncor Electric Delivery | Yes | |
| Transmission | Yes | |

| Organization | Question 2: | Question 2 Comments: |
|---|---|---|
| Reliability Program | | |
| Xcel Energy | Yes | |
| Texas-New Mexico Power Company | Yes | |
| American Public Power Association | Yes | |
| EPSA | | no comment |

3. The drafting team has modified the Violation Severity Levels for MOD-029 to reflect industry concerns that they were too “pass/fail” oriented. Are the current VSLs established correctly? If “No,” please identify specific VSLs and suggest changes to the language.

**Summary Consideration:**

Some commenter’s expressed concern with potential for multiple violations of the standard due to a single event. The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.

Some suggestions were made to change specific VSLs or measures and make them more graded. The SDT modified VSLs for R2, but did not modify the other measures or VSLs.

| Organization | Question 3: | Question 3 Comments: |
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| PJM | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations ?this language to be added to the standard. |
| **Response:** The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events. | | |
| Ontario IESO | No | We do not agree with the following VSLs:<br>a. R1 has two subrequirements: R1.1 for modeling details and R1.2 for use of facility ratings provided by the owners. A total failure of R1 would be failing both subrequirements. On this basis, we agree with the Low and Moderate but do not agree with the Severe which if changed, can impact the High VSL as well. For Severe, we suggest to change the condition to “AND” instead of “OR”. And with this change, the High would thus be for “3 or more” in the first condition and “21 or more” in the second condition, and the same language apply to the conditions for Severe, or something along that line in terms of the threshold numbers.<br>**Response:** After extensive discussion by the SDT, the SDT has determined that the VSL is appropriate as drafted.<br><br>b. There are 2 measures developed for R2 — an M3 for R2.7 and an M4 for the rest of R2 including R2.8 (a report that shows the process detailed in R2.1 to R2.6 was followed). Yet the VSL only has one entry, which appears to treat R2 as a binary requirement. There are at least two issues with this lone VSL: 1. M3 and M4 become irrelevant2. There is no provision for progressive (graded) VSLs for failing any of the subrequirements<br>**Response:** The SDT agrees and has changed the VSL to have a progressive grading.<br><br>c. We suggest the SDT review the measures in conjunction with the VSLs for this requirement. At a minimum, |

| Organization | Question 3: | Question 3 Comments: |
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| | | the VSLs should be dependent on the number of subrequirements not met. If the SDT wishes to have a simple set of VSLs, it may consider eliminating M3 hence making all subrequirements binary to support a progressive (graded) VSL for the main requirement.<br>**Response:** The SDT agrees and has changed the VSL to have a progressive grading, and as a result will not eliminate M3.<br><br>d. R5: For these VSLs to be appropriate, please see our comments and suggestion for changes on M7 under Q1.<br>**Response:** Please see response to Q1.<br><br>e. R6: For these VSLs to be appropriate, please see our comments and suggestion for changes on M8 under Q1.<br>**Response:** Please see response to Q1. |
| Southwest Power Pool | No | We do not agree with the following VSLs:<br>a. R1: R1 has two subrequirements: R1.1 for modeling details and R1.2 for use of facility ratings provided by the owners. A total failure of R1 would be failing both subrequirements. On this basis, we agree with the Low and Moderate but do not agree with the Severe which if changed, can impact the High VSL as well. For Severe, we suggest to change the condition to “AND” instead of “OR” And with this change, the High would thus be for “3 or more” in the first condition and “21 or more” in the second condition, and the same language apply to the conditions for Severe, or something along that line in terms of the threshold numbers.<br>**Response:** After extensive discussion by the SDT, the SDT has determined that the VSL is appropriate as drafted.<br><br>b. R2: There are 2 measures developed for R2 — an M3 for R2.7 and an M4 for the rest of R2 including R2.8 (a report that shows the process detailed in R2.1 to R2.6 was followed). Yet the VSL only has one entry, which appears to treat R2 as a binary requirement. There are at least two issues with this lone VSL:<br>i. M3 and M4 become irrelevant<br>ii. There is no provision for progressive (graded) VSLs for failing any of the subrequirements.<br>**Response:** The SDT agrees and has changed the VSL to have a progressive grading.<br><br>We suggest the SDT review the measures in conjunction with the VSLs for this requirement. At a minimum, the VSLs should be dependent on the number of subrequirements not met. If the SDT wishes to have a simple set |

| Organization | Question 3: | Question 3 Comments: |
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| | | of VSLs, it may consider eliminating M3 hence making all subrequirements binary to support a progressive (graded) VSL for the main requirement.<br>**Response:** The SDT agrees and has changed the VSL to have a progressive grading, and as a result will not eliminate M3.<br><br>c. R5: For these VSLs to be appropriate, please see our comments and suggestion for changes on M7 under Q1.<br>**Response:** Please see response to Q1.<br><br>d. R6: For these VSLs to be appropriate, Please see our comments and suggestion for changes on M8 under Q1.<br>**Response:** Please see response to Q1. |
| SMUD | Yes | |
| Kansas City Power & Light | Yes | |
| SMUD | Yes | |
| Northast Power Coordinating Council | Yes | |
| Public Service Commission of South Carolina | Yes | |
| Duke Energy Corporation | Yes | |
| Oncor Electric Delivery | Yes | |
| Transmission Reliability Program | Yes | |
| Pepco Holdings, Inc | | |
| Xcel Energy | Yes | |

| Organization | Question 3: | Question 3 Comments: |
| --- | --- | --- |
| Texas-New Mexico Power Company | Yes | |
| American Public Power Association | Yes | |
| EPSA | | no comment |

4. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-029.

**Summary Consideration:**

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

Several entities expressed concern regarding the responsibilities of the Transmission Operator. The SDT interprets the Functional Model as requiring the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. For those entities who believe the TSP to be the appropriate entity, we reiterate that options for delegation of this task exist.

The NERC RTOSDT expressed concern that the standard does not refer to Planning an operating limits. The SDT directed the RTOSDT to the specific areas in the methodology standard where such reference rare made.

The drafting team provided a summary of the use of time horizons to address some comments,

| Organization | Question 4 Comments: |
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| CenterPoint Energy | The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a single control area.<br>**Response:** This standard is intended to apply to all entities that have chosen to implement the Rated System Path methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub- |

| Organization | Question 4 Comments: |
|---|---|
| | regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* |
| ERCOT ISO | I suggest modifying the Applicability section to state""4.1. Each Transmission Operator with ATC Path(s) that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.""4.2. Each Transmission Service Provider with ATC Path(s) that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths."<br>**Response:** The SDT does not find that this adds further clarity, and has not made the suggested modification. |
| Austin Energy | These comments are filed on behalf of City of Austin d/b/a Austin Energy to address proposed NERC 5 MOD Standards. Austin Energy is a municipally owned electric utility and a transmission service provider with the Electric Reliability Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with no explicit transmission services being sold. Current ERCOT market rules allow open transmission access to all loads and resources. ERCOT will continue to operate as a Single Balancing Authority under Nodal market design. Accordingly, as explained in more detail below, the NERC 5 MOD Standards should not be applied to ERCOT and transmission service providers within ERCOT under its current or proposed Nodal market design. Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. Applicable definitions: According to NERC Reliability Standards Glossary of Terms, Available Transfer Capability (ATC) is defined as: – A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability (TTC) less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows? TTC is defined as: the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions. CBM is defined as the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. TRM also is a component of ATC defined as: that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. Comments: ERCOT is an interconnection and a region with no synchronous AC ties with any other interconnections. In July 2001, based on a deregulated Retail and restructured Wholesale Markets, the ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT market is designed such that there are no explicit transmission services being sold, hence, Available Transfer Capability (ATC) is not a measure used in a commercial activity within the ERCOT market. The current ERCOT market rules allow open transmission access to all eligible loads and resources without considering any specific Transmission Service Provider (TSP). Transmission facilities ratings are based upon individual branch element designs and in cases of dynamic ratings, ambient conditions are also considered. ERCOT has several DC ties and an asynchronous tie using a Variable Frequency Transformer (VFT); however, the associated interchange capabilities are planned and coordinated |

| Organization | Question 4 Comments: |
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| | by the TSPs involved. The current ERCOT Zonal Market uses a flow based congestion management methodology to predict potential congestions in the Day Ahead and Adjustment Periods. During the operating period, generation shift factors are used to determine the dispatch needed to remain within the constrained limits. The local congestions are managed using full AC load flow analysis and unit specific redispatch.MOD-001-1 is entirely about methodology and calculation of ATC, therefore, this standard is not applicable to ERCOT.MOD-008-1 covers Transmission Reliability Margin (TRM) methodology calculation. Mathematically, ATC is defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin (CBM). Therefore, TRM also is not applicable to ERCOT.MOD-028-1 covers Area Interchange calculation Methodology. Since ERCOT is a single control area, Area Interchange calculation is not applicable.MOD-029-1 covers Rated System Path Methodology, which is used to calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT.MOD-030-1 covers Flowgate methodology calculation of ATC, and therefore, is not applicable to ERCOT.ERCOT is currently transitioning to a Nodal Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a Security Constrained Economic Dispatch (SCED) approach to dispatch individual generating units and manage congestion. In the Nodal Market, ERCOT will still operate as a Single Balancing Authority. This again will not use ATC methodology, and aforementioned standards are not applicable to ERCOT in its ensuing Nodal Market. Therefore, Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations.<br>**Response:** This standard is intended to apply to all entities that have chosen to implement the Rated System Path methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. *(Loc. Cit.)* |
| Brazos Electric Power Cooperative, Inc. | Brazos Electric believes that the concept of the Rated System Path Methodology is not applicable to a single-control area operation like ERCOT. To address this issue, the Applicability section could have a clarifying statement that only TOPs or TSPs that conduct area to area operations and hence have responsibility for ATC Path(s) must have a Rated |

| Organization | Question 4 Comments: |
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| | System Path Methodology to support analysis and system operations.<br>**Response:** This standard is intended to apply to all entities that have chosen to implement the Rated System Path methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* |
| Oncor Electric Delivery | This standard should not apply to ERCOT for the reason expressed in question 1.<br>**Response:** This standard is intended to apply to all entities that have chosen to implement the Rated System Path methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* |
| Texas-New Mexico Power Company | This standard does not apply to ERCOT for the reason stated in Question 1.<br>**Response:** This standard is intended to apply to all entities that have chosen to implement the Rated System Path methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from |

| Organization | Question 4 Comments: |
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| | this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* |
| AEP | The Applicability of this Standard should be solely upon the TSP, the Transmission Operator should not be subject to this Standard.<br>**Response:** The Drafting Team does not find any clear rationale for selecting the Transmission Service Provider as the entity responsible for selecting the methodology. As discussed previously, the Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints.<br>For those entities who believe the TSP to be the appropriate entity, we reiterate that options for delegation of this task exist. Transmission operators can simply defer to the decisions made by their Transmission Service Provider; if a more formal agreement and transfer of responsibility is needed, the Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service provider agreeing to take on responsibility for this requirement through written contract.<br><br>From the previous set of responses, it is the apparent belief of the SDT that the calculation of ATC is needed for reliability (response to AECI for example). We disagree. Considering that ATC is a mathematical amalgamation of forecasted system conditions (load, outages, generation dispatch, others? transactions, etc) compounded and adjusted by margins (TRM and CBM of own entity and other systems), using the calculated ATC to assess real or near real time transmission reliability would be — at best — unwise. Transmission Reliability can be assessed by monitoring specific and individual Facility loadings and/or other parameters, for example. The calculation of ATC and the value of resultant ATC is exactly for the purpose stated in the definition of ATC: "A measure of" "capability" for further commercial activity? |

| Organization | Question 4 Comments: |
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| | — and note the definition does not infer ATC is a measure of reliability. Granted, ATC is calculated FROM reliability derived values and concepts (such as ratings, contingency analysis aspects, SOLs etc), BUT the resultant ATC values are not an assessment of transmission reliability — and therefore not a function for the Transmission Operators, but rather the Transmission Service Provider.<br>**Response:** FERC has already opined that ATC is a reliability issue. In Order 693, FERC held that:<br>"1022. We disagree with MISO's contention that the Reliability Standards are an inappropriate venue for addressing ATC comparability issues. *ATC raises both comparability and reliability issues*, and it would be irresponsible to take action under FPA section 206 to require consistency in ATC calculations without considering the reliability impact of those decisions." (See also P. 1014.) (Emphasis added.)<br>Docket No. RM06-16-000; 18 CFR Part 40; Mandatory Reliability Standards for the Bulk-Power System. Issued March 16, 2007)<br><br>In addition, the Purpose statement is unclear and perhaps nonsensical. Is the purpose "to increase consistency and reliability in the development of documentation".? or "to support analysis and system operation"? What entities? "short term use" Suggestion: Purpose: To ensure consistency of calculation of those entities employing Rated System Path Methodology pursuant to MOD-001 R1.<br>**Response:** The SDT believes that AEP has inaccurately quoted the language of the "Purpose" statement as being for "the development *of documentation*" (emphasis added); whereas the actual Purpose statement is to promote "the development and documentation *of transfer capability calculations*." (emphasis added). This statement clearly aligns with FERC's Order 693, P. 1015 wherein FERC states the purpose of the ATC suite is to promote "consistency and transparency for ATC calculations." As for the ambiguity of applicable entities in the Purpose statement, AEP is reminded that the Applicable entities are clearly stated in the Applicability section – not the Purpose section. As for short-term, FERC suggests that short-term is operational whereas long-term is planning in nature. Order 693, P. 1040. See also Order 890, P. 292 – 295 |
| Transmission Reliability Program | BPA respectfully submits the following observations and suggestions: a. Including counterflows in the calculation of firm ATC is not appropriate because it could result in exceeding a TTC limit due to forced outage scenarios. An accurate estimation of counterflows cannot be assured and may result in over selling transmission. R7 should be modified to state that for firm ATC calculations counterflows shall always be zero.<br>**Response:** Use of counter flows to calculate firm ATC is an option not an obligation and is an accepted practice within the industry. Within the WECC Rated System Path method counter schedules are used instead of counter flows.<br><br>b. The Time Horizons listed for all requirements should include the "Long-term Planning" Horizon, as ATC is to be calculated beyond the seasonal window. |

| Organization | Question 4 Comments: |
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| | **Response:** The use of "Time Horizons" in this standard is in the form of a compliance element, and refers to the manner in which compliance evaluates the implications of a violation of the standard. In this context, time horizon has to do with the urgency of addressing a violation, e.g., how quickly a violation needs to be rectified. Together, the Violation Risk Factor and Time Horizon aid a compliance auditor in determining sanctions. Accordingly, the SDT believes that the appropriate horizon for compliances does not include "Long-term Planning."<br><br>c. Balancing Authorities may be appropriately identified as Applicable Entities in this MOD and request that the Standards Drafting Team provide an explanation as to why they are not listed.<br>**Response:** The SDT is uncertain what tasks BPA would assign to the Balancing Authority. To the extent that BPA has suggested requirements or tasks for the BAs to perform, the SDT suggests that BPA draft a SAR to incorporate those requirements in a future revision to the standard. |
| Southwest Power Pool | The extent to which standard MOD-029 is able to attain consistency in calculating ATC in-part depends on the definitions of terms used in the formulas. Unfortunately, the definition of the word "commitment" is not specific enough to be useful. In fact, the same phrase ("existing transmission commitment") is calculated differently in R5 than R6. For this reason, the term "ETC" should be dropped from standard MOD-029 and defined terms used.<br>**Response:** ETC is calculated the same in R5 and R6, it is the subscript that differentiates R5 from R6. The subscript defines the component as either firm or non-firm.<br><br>R6 defines PTP Non-Firm as including reserved capacity and should only include tagged or scheduled capacity. Capacity that is reserved but not scheduled should not affect NF ATC.<br>**Response**: Only including tagged or scheduled capacity would result in unchecked sale of non-firm service, resulting in potential adverse affect to the reliability of the system.<br><br>It is also important that the same time periods be used to define the three time periods (scheduling horizon, operating horizon, and planning horizon) within an interconnect (i.e. the WECC) so that the same ATC algorithm is applied in all BAs across an interconnect for the same hour.<br>**Response:** The SDT has identified the periods for which different methodologies are allowed in mod 001 R2. We do not agree that all entities within an interconnection must use the same methodology. |
| PJM | PJM reiterates that while we will not choose the calculation methodologies used in MODs 28 and 29, these MODs will require modification to assure consistency with any revisions made to MOD 30. PJM is including specific comments for MOD 30 in Section VI of this document. PJM is not providing specific comments for MODs 28 and 29.<br>**Response:** The SDT will work to maintain consistency between the three MOD standards. |

| Organization | Question 4 Comments: |
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| SMUD | The WECC Team notes that changing the modeling equivalence threshold within MOD-29 to match that of the other methodologies creates a seamless and equal application across all methodologies for all of NERC.<br>**Response:** Thank you for your supportive comments. |
| American Public Power Association | Excellent work<br>**Response:** Thank you for your supportive comment. |
| SMUD | The WECC Team notes that changing the modeling equivalence threshold within MOD-29 to match that of the other methodologies creates a seamless and equal application across all methodologies for all of NERC.<br>**Response:** Thank you for your supportive comments. |
| EPSA | no comment |
| Ontario IESO | None |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007
6. SC Conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

## A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining TTC: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

**R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

**R1.3.** Any contractual obligations for allocation of TTC.

**R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.

**R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.5.1.** Define if the source used for ATC calculations is obtained from the source field or the POR field of the transmission reservation

**R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the POD field of the transmission reservation

**R1.5.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.5.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

**R2.** When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities161kV or below is allowed.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** For on-peak and off-peak intra-day and next-dayTTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R3.1.2.** Load forecast for the applicable period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

**R3.2.2.** Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.** When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Use all Contingencies meeting the criteria described in its ATCID.

**R4.2.** Respect any contractual allocations of TTC.

**R4.3.** Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated

with the Transmission Service Provider to which the power is being delivered as the sink.

**R5.** Each Transmission Operator shall establish TTC for each ATC Path as defined below: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** At least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations.

**R5.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R5.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

**R6.** Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

**R6.2.** If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R6.3.** Use (as the TTC) the lesser of:

– The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or

– The sum of Facility Ratings of all ties comprising the ATC Path.

**R6.4.** For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed that Transmission Operator's contractual rights.

**R7.** The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

[1] The Transmission operator may honor distribution factors less than 5% if desired.

**R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

**R8.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NITS_F$** is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_F$** is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R9.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_{NF}$** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access

Transmission Tariff or “Safe Harbor Tariff” accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R10.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + counterflows_F$$

**Where:**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

**R11.** When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

**M4.** Each Transmission Operator shall provide the contingencies used in determining TTC and its ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

**M5.** Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

**M6.** Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

**M7.** Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)

**M8.** Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)

**M9.** Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

**M10.** The TSP must be capable of demonstrating that for any calculation of firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the firm ETC for a specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R8)

**M11.** The TSP must be capable of demonstrating that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the non-firm ETC for a specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R9)

**M12.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)

**M13.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc.). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset

Not applicable.

#### 1.3. Data Retention

The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.

The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.

The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.

The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.

The Transmission Service Provider shall retain evidence to show compliance with R8 and R9 for the most recent sixty days.

The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.

If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has an ATCID that meets the intent of Requirement 1 but the ATCID is missing some minor information. | The Transmission Service Provider has an ATCID but it is missing one of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing two of the four required elements in R1. | The Transmission Service Provider has an ATCID but it is missing three or more of the four required elements in R1. |
| R2. | The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>**OR**<br><br>The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator area.<br><br>Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. | The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br><br>**OR**<br><br>The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator area.<br><br>**OR**<br><br>The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator areas.<br><br>Note: A modeling error (a |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. |
| R3. | The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.<br>**OR**<br>The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3. |
| R4. | The Transmission Service Provider did not model reservations' sources or sinks as described in R4.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater. | The Transmission Service Provider did not model reservations' sources or sinks as described in R4.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater. | The Transmission Service Provider did not model reservations' sources or sinks as described in R4.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater. | The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br>**OR**<br>The Transmission Operator did not respect contractual allocations of TTC.<br>**OR**<br>The Transmission Service Provider did not model reservations' sources or sinks as described in R4.3 for more than 15% of all reservations; or more |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | than 3 reservations, whichever is greater.<br>**OR**<br>The Transmission Operator did not use firm reservations to estimate interchange or did not utilize that estimate in the TTC calculation as described in R4.3. |
| R5. | N/A | N/A | N/A | The Transmission Operator did not establish TTCs within the minimum time frames specified in R5. |
| R6. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the process specified in R6. |
| R7. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.<br>**OR**<br>The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination.<br>**OR**<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations.<br>**OR** |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | seven calendar days after their determination, but not more than 14 calendar days since their determination. | calendar days after their determination, but not been more than 21 calendar days after their determination. | calendar days after their determination, but not been more than 28 calendar days after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination.<br>**OR**<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations. |
| R8. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M9 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M9 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M9 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M9 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R9. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R10. | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |
| R11. | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |

## E. Regional Variances

None.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC Conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

## A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. **Applicability:**

    **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

    **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities~~, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees~~.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining TTC: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

**R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

**R1.3.** Any contractual obligations for allocation of TTC.

**R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.

**R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.5.1.** Define if the source used for ATC calculations is obtained from the source field or the POR field of the transmission reservation

**R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the POD field of the transmission reservation

**R1.5.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.5.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

**R2.** When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Lower~~Medium~~] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities161kV or below is allowed.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs ~~(for intra-day and next-day)~~ for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: Lower~~Medium~~*] [*Time Horizon: Operations Planning*]

**R3.1.** For on-peak and off-peak intra-day and next-dayTTCs, ~~and on-peak next-day TTCs,~~ use the following (as well as any other values and additional parameters as specified in the ATCID):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R3.1.2.** Load forecast for the ~~on-peak~~applicable period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For ~~off-peak intra-day and off-peak next-day~~days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

**R3.2.2.** Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.

~~**R3.2.2.** Load forecast for the off-peak period being calculated.~~

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

~~**R4.** When calculating TTCs (for time periods beyond next day) for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*~~

~~**R4.1.** For days two through 31 TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):~~

~~**R4.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.~~

~~**R4.1.2.** Load forecast for the day being calculated.~~

~~**R4.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.~~

~~**R4.2.** For months two through 13 TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):~~

~~**R4.2.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.~~

~~**R4.2.2.** Load forecast for the month calculated.~~

~~**R4.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.~~

**R4.** When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Use all Contingencies meeting the criteria described in its ATCID.

**R4.2.** Respect any contractual allocations of TTC.

**R4.3.** Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

**R5.** Each Transmission Operator shall ~~calculate~~ establish TTC for each ATC Path as defined below~~, unless otherwise requested by the Transmission Service Provider~~: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** At least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations.

**R5.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R5.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer~~ in duration~~.

**R6.** Each Transmission Operator shall ~~calculate~~ establish TTC for each ATC Path using the following process: *[Violation Risk Factor: Lower~~Medium~~] [Time Horizon: Operations Planning]*

**R6.1.** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

**R6.2.** If the limit in step ~~R7~~R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R6.3.** Use (as the TTC) the lesser of:

– The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or

– The sum of Facility Ratings of all ties comprising the ATC Path.

**R6.4.** For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed that Transmission Operator's contractual rights.

**R7.** The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Lower~~Medium~~] [Time Horizon: Operations Planning]*

**R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

**R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

**R8.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower~~Medium~~] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

[1] The Transmission operator may honor distribution factors less than 5% if desired.

**Where:**

**$NITS_F$** is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_F$** is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R9.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_{NF}$** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R10.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Lower~~Medium~~] [Time Horizon: Operations Planning]*

$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + \cancel{Counterflow}counterflows_F$

**Where:**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm ATC due to a change in the use of ~~Firm~~ Transmission Service for that period, as defined in Business Practices.

**~~Counterflow~~counterflows$_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

**R11.** When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + \cancel{Counterflow}counterflows_{NF}$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm ATC due to a change in the use of ~~Non-Firm~~ Transmission Service for that period, as defined in Business Practices.

**~~Counterflow~~counterflows$_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3) ~~(R4)~~

**M4.** Each Transmission Operator shall provide the contingencies used in determining TTC and its ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4~~5~~)

**M5.** Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4~~5~~.2. (R4~~5~~)

**M6.** Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4~~5~~.3, and that estimated scheduled interchange was included in the determination of TTC. (R4~~5~~)

**M7.** Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to ~~calculate~~ establish TTCs at specific intervals) that TTCs have been ~~calculated~~ established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5~~6~~.(R5~~6~~)

**M8.** Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6~~7~~. (R6~~7~~)

**M9.** Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7~~8~~. (R7~~8~~)

**M10.** The TSP must be capable of demonstrating that for any calculation of firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the firm ETC for a specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R8)

~~**M10.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ETC used the algorithm and elements described in R9 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R9)~~

**M11.** The TSP must be capable of demonstrating that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the non-firm ETC for a specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate this specified value for the designated hour. The data used must meet the requirements specified in the standard and the ATCID, and the audited value must be within +/- 15% or 15 MW, whichever is greater, of the demonstrated result. (R9)

~~**M11.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ETC used the algorithm and the elements described in R10 and did not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R10)~~

**M12.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10) ~~Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of firm ATC used the algorithm and the elements described in R11 and does not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R11)~~

**M13.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc.). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

~~**M13.** Each Transmission Service Provider shall provide evidence (such as documentation and data) that the determination of non-firm ATC used the algorithm and the elements described in R12 and does not include any additional elements. Note that variables may legitimately be zero if the value is not applicable or calculated to be zero. (R12)~~

## D. Compliance

### 1. Compliance Monitoring Process

### 1.1. Compliance Enforcement Authority

Regional Entity.

### 1.2. Compliance Monitoring Period and Reset

Not applicable.

### 1.3. Data Retention

The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.

The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.

The Transmission Operator shall retain evidence to show compliance with R3 ~~and R4~~ for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.

The Transmission Operator shall retain evidence to show compliance with R4~~5~~, R5~~6~~, R~~7~~6 and R7~~8~~ for the most recent 12 months.

The Transmission Service Provider shall retain evidence to show compliance with R8~~9,~~ and R9~~10, R11 and R12~~ for the most ~~recent12~~ recent sixty days~~months~~.

The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.

If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| **R1.** | **The Transmission Service Provider has an ATCID that meets the intent of Requirement 1 but the ATCID is missing some minor information.** | **The Transmission Service Provider has an ATCID but it is missing one of the four required elements in R1.** | **The Transmission Service Provider has an ATCID but it is missing two of the four required elements in R1.** | **The Transmission Service Provider has an ATCID but it is missing three or more of the four required elements in R1.** |
| **R2.** | **The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.**<br><br>**Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled.** | **The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.**<br><br>**Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled.** | **The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.**<br><br>**OR**<br><br>**The Transmission Operator did not ~~include in the~~use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator area.**<br><br>**Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled.** | **The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.**<br><br>**OR**<br><br>**The Transmission Operator's model -includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator area.**<br><br>**OR**<br><br>**The Transmission Operator did not ~~not include in the~~use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator areas.** |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled. |
| R3. | The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID~~.~~. | The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID~~.~~. | ~~In calculating TTCs for intra-day and next-day, the~~The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.<br>OR<br>~~In calculating TTCs for intra-day and next-day, the~~The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3~~.1~~. |
| ~~R4.~~ | ~~N/A~~ | ~~N/A~~ | ~~N/A~~ | ~~In calculating TTCs for time periods beyond next day, the Transmission Operator did not include more than fifty expected generation and Transmission outages, additions or retirements in the TTC process.~~<br>~~OR~~<br>~~In calculating TTCs for time~~ |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | ~~periods beyond next-day, the Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R4.1.~~ |
| ~~R5~~R4. | The Transmission Service Provider did not model reservations' sources or sinks as described in R4.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater.<br><br>~~.N/A~~ | The Transmission Service Provider did not model reservations' sources or sinks as described in R4.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater.<br><br>~~.N/A~~ | The Transmission Service Provider did not model reservations' sources or sinks as described in R4.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater.<br><br>~~.N/A~~ | The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br><br>OR<br><br>The Transmission Operator did not respect contractual allocations of TTC.<br><br>OR<br><br>The Transmission Service Provider did not model reservations' sources or sinks as described in R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater.<br><br>~~The Transmission Operator did not model reservations' sources or sinks as described in R5.3~~<br><br>OR<br><br>The Transmission Operator did not use firm reservations to estimate interchange or did |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | not utilize that estimate in the TTC calculation as described in R4~~5~~.3. |
| ~~R6~~R5. | N/A | N/A | N/A | The Transmission Operator did ~~calculated~~ not establish TTCs ~~in excess of~~within the minimum time frames specified in R5~~6~~. |
| ~~R7~~R6. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the process specified in R6~~7~~. |
| R7~~8~~. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.<br>OR<br>The Transmission Operator has not -provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.<br>OR<br>The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.<br>OR<br>The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination. | The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination.<br>OR<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations.<br>OR<br>The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | 28 calendar days after their determination.<br>OR<br>The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations. |
| R8~~9~~. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M9 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. ~~.N/A~~ | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M9 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. ~~N/A~~ | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M9 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. ~~.N/A~~ | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M9 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.~~The Transmission Service Provider did not use all the elements defined in R9 when determining firm ETC, or used additional elements.~~ |
| R9~~10~~. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.~~N/A~~ | than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.~~..N/A~~ | than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. ~~N/A~~ | than 45% of the value calculated in the measure or 45MW, whichever is greater.~~The Transmission Service Provider did not use all the elements defined in R10 when determining non-firm ETC, or used additional elements.~~ |
| R10~~1~~. | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). ~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). ~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). ~~N/A~~ | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).~~The Transmission Service Provider did not use all the elements defined in R11 when determining firm ATC, or used additional elements.~~ |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| **R11~~2~~.** | **The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).** <br> **~~N/A~~** | **The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).~~N/A~~** | **The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).~~N/A~~** | **The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).** <br> **~~The Transmission Service Provider did not use all the elements defined in R12 when determining non-firm ATC, or used additional elements.~~** |

## E. Regional Variances

None.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Implementation Plan for Standard MOD-028-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-028-1 — Area Interchange Methodology, which describes the Area Interchange methodology (previously referred to as the Network Response ATC methodology) for determining ATC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Retired Standards

FAC-012-1 — Transfer Capability Methodology includes four requirements. MOD-028-1 incorporates the following requirements from FAC-012-1:

– R1 (Documentation of the Transfer Capability Methodology).

– R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

– R4 (Responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

FAC-013-1 — Establish and Communicate Transfer Capabilities, includes two requirements. MOD-028-1 incorporates the following requirements from FAC-013-1:

– R1 (Calculation of the Transfer Capabilities).

– R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-~~012~~013-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-028-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

## Implementation Plan for Standard MOD-028-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-028-1 — Area Interchange Methodology, which describes the Area Interchange methodology (previously referred to as the Network Response ATC methodology) for determining ATC.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### ~~Modified~~ Retired Standards

FAC-012-1 — Transfer Capability Methodology includes four requirements. MOD-028-1 ~~This standard~~ incorporates the following requirements from FAC-012-1:

– R1 (Documentation of the Transfer Capability Methodology).

– R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

– R4 (Responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

FAC-013-1 — Establish and Communicate Transfer Capabilities, includes two requirements. ~~This standard~~MOD-028-1 incorporates the following requirements from FAC-013-1:

– R1 (Calculation of the Transfer Capabilities).

– R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-~~012~~013-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-028-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities~~, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001, MOD-028, MOD-029, and MOD-030 are approved by the NERC Board of Trustees~~. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

Please **DO NOT** use this form to submit comments on the current draft of MOD-028. Comments must be submitted by **May 15, 2008.**

If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-452-8060.

**Background Information — MOD-028 — Area Interchange Methodology** (A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection.)

An initial ballot of MOD-028-1 — Area Interchange Methodology was conducted March 3-12, 2008 and there were several suggestions for modifying the standard that were submitted with ballots. The drafting team withdrew the standard from the ballot process, and made several changes to the standard based on stakeholder comments, including the following:

1. Several VRFs were changed from "Medium" to "Lower" in response to industry comments.. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
2. A more graded approach was applied to the VSLs where appropriate.
3. During the review of the VSLs and Measures, it was determined that the measures for R8, R9, R10, and R11 did not adequately measure compliance with the requirements. The drafting team updated the measures and VSLs to ensure that they captured the need to have accurate and valid numbers used in the requirements.

**Please review the revised version of MOD-028 and then answer the following questions. You do not have to answer all questions. Enter All Comments in Simple Text Format.**

1. **The drafting team modified some requirements and associated measures in MOD-028 to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct.**

   Incorrect Requirement(s) or Measure(s):

2. **The drafting team has modified the Violation Risk Factors for MOD-028 to reflect industry concerns that they did not match NERC's VRF definitions. NERC's VRF definitions are listed below:**

   **High Risk Requirement**:
   (a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or
   (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

   **Medium Risk Requirement**:
   (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or
   (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

   **Lower Risk Requirement**: is administrative in nature and
   (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or
   (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

   **Are the current VRFs established correctly?**

   ☐ Yes

☐ No

**If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.**
Comments:

3. **The drafting team has modified the Violation Severity Levels for MOD-028 to reflect industry concerns that they were too "pass/fail" oriented. Are the current VSLs established correctly?**

   ☐ Yes
   ☐ No

   **If "No," please identify specific VSLs and suggest changes to the language.**
   Comments:

4. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-028.**

   Comments:

| | Individual or group. | Name | Organization | Group Name | Lead Contact | Question 1 | Question 2 | Question 2 Comments | Question 3 | Question 3 Comments | Question 4 Comments |
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| | Individual | Jack Cashin/Barry Green | EPSA | | | Through this revision process, some of the MOD standards have included an explicit requirement for consistency between planning assumptions and modeling assumptions used in calculation of ATC. We believe this is appropriate and should be included in MOD 028. | | no comment | | no comment | no comment |
| | Individual | Jim Useldinger | Kansas City Power & Light | | | The Transmission Service Provider should be added along with TOP to perform these functions in all requirements | Yes | | Yes | | |
| | Individual | Paul Rocha | CenterPoint Energy | | | | | | | | The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a single control area. |
| | Group | | | SERC ATCWG | Doug Bailey | | Yes | | Yes | | |
| | | | | | | Requirement 1: I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining TTC:" Requirement 2: I suggest modifying the requirement to state: "When calculating TTC for ATC Paths, the Transmission Operator with ATC Path(s) shall use a Transmission model that contains all of the following:" Requirement 3: I suggest modifying the requirement to state: "When calculating TTCs for ATC Paths, the Transmission Operator with ATC Path(s) shall | | | | | |

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| | Individual | H. Steven Myers | ERCOT ISO | | | include the following data for the Transmission Service Provider's area. The Transmission Operator with ATC Path(s) shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed:" Requirement 4: I suggest modifying the requirement to state: "When calculating TTCs for ATC Paths, the Transmission Operator with ATC Path(s) shall meet all of the following conditions:" Requirement 5: I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path (s) shall establish TTC for each ATC Path as defined below:" Requirement 6: I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path (s) shall establish TTC for each ATC Path using the following process:" Requirement 7: I suggest modifying the requirement to state: "The Transmission Operator with ATC Path (s) shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:" Requirement 8: I suggest modifying the requirement to state: "When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETCF) for all time periods for an ATC Path the Transmission Service Provider with ATC Path(s) shall use the following algorithm:" Requirement 9: I suggest modifying the requirement to state: "When calculating ETC for non-firm commitments (ETCNF) for all time periods for | | | | | I suggest modifying the Applicability section as follows: "4.1. Each Transmission Operator with ATC Path(s) that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths." "4.2. Each Transmission Service Provider with ATC Path(s) that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths." |

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| | | | | | | an ATC Path the Transmission Service Provider with ATC Path (s) shall use the following algorithm:" Requirement 10: I suggest modifying the requirement to state: "When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider with ATC Path (s) shall utilize the following algorithm:" Requirement 11: I suggest modifying the requirement to state: "When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:" | | | | | |
| | Group | | | NERC RTOSDT | Jim Case, Chair | | | | | | The Real Time Operation Standards Drafting Team is concerned that the proposed MOD standards do not include any reference to the Planning and Operating Limits mandated by the current FAC, IRO and TOP standards. These standards already include transmission flow limits both in the longer term planning time frame as well as the shorter term operating time frame. The proposed MOD standards seem to be establishing procedures to calculate the commercial boundaries without a direct link to the required reliability boundaries. ============================================================ MOD-001 R6 states that the TTC "use assumptions" no more limiting than those used in planning. The RTO SDT would ask shouldn't TTC's be required to be "no less limiting" than the SOLs / IROLs computed for the system? Current NERC standards are not just asset limits, they are also system limits. The current standards require that limits be calculated that recognize both local and wide-area impacts. The RTO SDT believes that by at least linking (if not entirely eliminating) the MOD standards to the current SOLs / IROLs requirements, the Industry would be more correctly linking how the system MUST BE operated to any NAESB business practice. Indeed it would seem that current tariffs are based on the computations used in current planning and operating environments. By using the current SOL / IROL limits the procedural / prescriptive requirement in MOD-001 R9 et al would be unnecessary (i.e. they would revert back to the FAC and IRO requirements) The questions for the ATC SDT: • How do these MOD standards relate to the SOLs / IROLs • Why should these ATC/TTC limits be decoupled from the SOLs / IROLs • Shouldn't the long-term SOL / IROL limits computed in Planning be the TTC for the system (or at least the basis for the TTC) • Shouldn't the short-term SOL / IROL be the basis for the ATC for the system? MOD-008 computes margins. By coordinating the MOD standards with the SOL / IROL standards, the only Business (not NERC) requirement may be to define the options on how the TSP could couple the various SOL / IROL values that it obtains from its RCs and TOPs. MOD-028 By using SOLs / IROLs there would be no need to get into ATC / AFC "methodologies". Indeed standards that include "alternatives" are not defining a single "standard approach". But by using specific planning and operating limits the methodologies become irrelevant. The "limit" becomes explicit and well-defined. Any margins or variations about those limits would then be obvious and transparent. What is most important is respecting the reliability-based limits and not how the commercial value is computed. If this idea of using SOLs / IROLs as the limit(s) or at least the basis for those commercial limits, then the TSP becomes a coordinator of which values to use for the commercial periods. The TSP would not be the computer of those limits. Thus MOD-028 could become a business practice for posting – rather then a standard for computations. |
| | Group | | | NPCC Regional Standards | Guy V. Zito | a. R4.1: The "its" before ATCID should be replaced with "the" or "the Transmission Service Provider's" since the ATCID is the TSP's document. Same change to M4. b. R6.4: In general, a TOP doesn't have contractual rights of a jointly-owned or allocated facility, whereas the TSP does. We suggest this requirement be revised | No | No, those requirements (at least R5 and R6) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission | | | |

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| | | | | Committee | | to “For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed the contractual rights of the Transmission Service Provider of that ATC path.” c. M11: Same comment on M10 also applies here for R9 | | services. Failure to establish TTCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable operation. | | | |
| | Individual | Thad Ness | AEP | | | | | | | | The Applicability of this Standard should be solely upon the TSP, the Transmission Operator should not be subject to this Standard. From the previous set of responses, it is the apparent belief of the SDT that the calculation of ATC is needed for reliability (response to AECI for example). We disagree. Considering that ATC is a mathematical amalgamation of forecasted system conditions (load, outages, generation dispatch, others' transactions, etc) compounded and adjusted by margins (TRM and CBM of own entity and other systems), using the calculated ATC to assess real or near real time transmission reliability would be – at best – unwise. Transmission Reliability can be assessed by monitoring specific and individual Facility loadings and/or other parameters, for example. The calculation of ATC and the value of resultant ATC is exactly for the purpose stated in the definition of ATC: “A measure of … capability….for further commercial activity” – and note the definition does not infer ATC is a measure of reliability. Granted, ATC is calculated FROM reliability derived values and concepts (such as ratings, contingency analysis aspects, SOLs etc), BUT the resultant ATC values are not an assessment of transmission reliability – and therefore not a function for the Transmission Operators, but rather the Transmission Service Provider. In addition, the Purpose statement is unclear and perhaps nonsensical. Is the purpose “to increase consistency and reliability in the development of documentation….” or “to support analysis and system operation”? What entities' “short term use”? Suggestion: Purpose: To ensure consistency of calculation of those entities employing Area Interchange Methodology pursuant to MOD-001 R1. |
| | Group | | | Public Service Commission of South Carolina | Phil Riley | | Yes | | Yes | | |
| | Individual | Greg Rowland | Duke Energy Corporation | | | R1 – Need to ensure that comparable information should be required in either the study report or the ATCID in MOD-028, MOD-029 and MOD-030. R2.1 - Bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on TTC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders. | Yes | | Yes | | |
| | | | | | | | | PJM supports NERC's position to revise all Violation Risk Factors to have an assigned risk factor of “Lower.” A Lower Risk Factor requirement is administrative | | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a | |

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| | | | | | | | | in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. | | concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations –this language to be added to the standard. | |
| | Individual | Patrick Brown | PJM | | | PJM does not have any specific comments. | Yes | | No | | PJM reiterates that while we will not choose the calculation methodologies used in MODs 28 and 29, these MODs will require modification to assure consistency with any revisions made to MOD 30. PJM is including specific comments for MOD 30 in Section VI of this document. PJM is not providing specific comments for MODs 28 and 29. |
| | Individual | Greg Ward / Darryl Curtis | Oncor Electric Delivery | | | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). | Yes | | Yes | | This standard should not apply to ERCOT for the reason expressed in question 1. |
| | Group | | | Bonneville Power | Denise Koehn | BPA does not believe any are incorrect. | Yes | | Yes | | none |
| | Individual | Richard Kafka | Pepco Holdings, Inc | | | PHI supports the comments of PJM and will not submit duplicate comments | | | | | |
| | Individual | Earl Fair | Gainesville Regional Utilities | | | In R8&9, must you determine ETC by only using the inputs specified, or can you determine each one separately then sum them to get ETC? Some methods for determining ETC may not take into account each individual item and its effect on a given path. | Yes | | Yes | Good improvement. | None at this time. |
| | | | | | | | | | | No. We suggest the following changes: a. R1: R1.5 contains | |

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| | | | | | | | | | several subrequirements. It is not clear what constitutes a failure of R1.5 when considering the VSLs for R1 (i.e. number of elements missing in the ATCID. For similar situations in MOD-008, it is stipulated that failing any one of the subrequirements would constitute a requirement failure. We therefore suggest adding a sentence under each of Moderate, High and Severe: “Any violation or violations of the sub-requirements of R1.5 shall be considered a single violation of R1.5.” b. R2: We do not agree with the VSL assignments. Note that R2 has 3 subrequirements, hence a Moderate should be assigned for failing 1 of the 3, a High for failing 2 and a Severe for failing all 3. A progressive VSL for R2.3 doesn't work in this case since even having >30 incorrect ratings, the TOP would have only failed one of the 3 subrequirements and should not be assigned a Severe if it met the other 2. We suggest the SDT to revise these VSLs. c. R3: We do not agree with the VSL assignment. R3 has two subrequirements: R3.1 for on-peak and off-peak intra-day and next-day TTCs, and R3.2 for days two through 31 TTCs and for months two through 13 TTCs. A total failure of R3 would be | |

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| | Group | | | IRC Standards Review Committee | Charles Yeung | a. R4.1: The "its" before ATCID should be replaced with "the" or “the Transmission Service Provider’s” since the ATCID is the TSP’s document. Same change to M4. b. R6.4: In general, a TOP doesn’t have contractual rights of a jointly-owned or allocated facility, whereas the TSP does. We suggest this requirement be revised to “For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed the contractual rights of the Transmission Service Provider of that ATC path.” c. M10: This measure corresponds to R8, which stipulates the use of a specific algorithm. However, M10 provides the requirement for certain accuracy, which leads to the following questions: i. Is R8 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm? ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M10) to determine if the algorithm and its settings have been properly used. iii. If accuracy is to be a | No | No, those requirements (at least R5 and R6) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable operation. | No | failing both subrequirements. Within each of the subrequirements, there are 3 subrequirements. While the VSLs for each of R3.1 and R3.2 can be made progressive (graded) according to the extent of missing outages, additions, retirements, and load forecast and unit commitments, etc. they need to eventually be factored in the VSLs for R3. Suggest to revise the VSLs so that a Low would be missing some of the subrequirements in either R3.1 and R3.2, a Moderate for missing more of them, and so on with a Severe be assigned if the majority of the subrequirements in both R3.1 and R3.2 are missing. Better still, the SDT may consider rearranging R3 so that they can better facilitate VSL development. d. R4: Similar comments in R3 also apply here. In this case, modeling reservations’ sources or sinks is used as the parameter to assign progressive VSLs, leaving the violation of either R4.1 or R4.2 or failure to include firm transmission service (a part of R4.3) as the condition for a Severe. It appears that the impact of violation has been applied in arriving at the assigned VSLs, which is not proper. We | |

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| | | | | | | criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure. d. M11: Same comment on M10 also applies here for R9. | | | | suggest a rework of this set of VSL so that they are dependent on the extent to which the 3 subrequirments are violated. If necessary, the SDT may want to consider splitting R4.3 to separate out the inclusion of firm reservations requirement to make it a condition for assessing VSLs. e. R5: We do not agree that the VSL should be a single “Severe”. R5 contains 3 subrequirements. Presumably, a TSP may fail one or more of these subrequirements. A progressive (graded) VSL should be developed. f. R6: We assess that R6.1 and R6.2 are parts of a single process requirement. However R6.3 and R6.4 are distinct requirements that need to be met as well. Presumably, a TSP may fail anyone or more of the 3 subrequirements (R6.1 and R6.2 as a unit). Again, a progressive (graded) approach would be more appropriate. We suggest the SDT to revise the VSL for this requirement. g. R7: the second “OR” under the Severe column should be “AND” since the first two conditions both mean that the TOP fails R7.1 completely, but it’s only a part of R7. It needs to also fail R7.2 completely to have a Severe failure. To cover for case where the TOP fails either R7.1 or | |

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| | | | | | | | | | | R7.2 completely but not both, the conditions under High may be revised to remove the "but not been more than" parts and include the "did not provide…" as an OR condition. h. R8: We would assume the "M9" referenced in this set of VSL really meant "M10", or else these VSLs would be difficult to understand since R8 is on using the algorithm, not on the values whereas M9 is for R7 that stipulates the requirement for establishing TTC values. Please also see our comments on M10 under Q1. i. R9: Same comment as in VSLs for R8, except in this case the "M10" should be "M11". Please also see our comments on M11 under Q1. | |
| | | | | | | | | | | We suggest the following changes: a. R1: R1.5 contains several subrequirements. It is not clear what constitutes a failure of R1.5 when considering the VSLs for R1 (i.e. number of elements missing in the ATCID. For similar situations in MOD-008, it is stipulated that failing any one of the subrequirements would constitute a requirement failure. We therefore suggest adding a sentence under each of Moderate, High and Severe: "Any violation or violations of the sub-requirements of R1.5 shall be considered a single violation of R1.5." b. R2: We do not agree with the VSL | |

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| | | | | | | 1. We offer the following comments/suggestions: a. R4.1: The "its" before ATCID should be replaced with "the" or "the Transmission Service Provider's" since the ATCID is the TSP's document. Same change to M4. b. R6.4: In general, a TOP doesn't have contractual rights of a | | | | assignments. Note that R2 has 3 subrequirements, hence a Moderate should be assigned for failing 1 of the 3, a High for failing 2 and a Severe for failing all 3. A progressive VSL for R2.3 doesn't work in this case since even having >30 incorrect ratings, the TOP would have only failed one of the 3 subrequirements and should not be assigned a Severe if it met the other 2. We suggest the SDT to revise these VSLs. c. R3: We do not agree with the VSL assignment. R3 has two subrequirements: R3.1 for on-peak and off-peak intra-day and next-day TTCs, and R3.2 for days two through 31 TTCs and for months two through 13 TTCs. A total failure of R3 would be failing both subrequirements. Within each of the subrequirements, there are 3 subrequirements. While the VSLs for each of R3.1 and R3.2 can be made progressive (graded) according to the extent of missing outages, additions, retirements, and load forecast and unit commitments, etc. they need to eventually be factored in the VSLs for R3. Suggest to revise the VSLs so that a Low would be missing some of the subrequirements in either R3.1 and R3.2, a Moderate for | |

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| | Individual | Ron Falsetti | Ontario IESO | | | jointly-owned or allocated facility, whereas the TSP does. We suggest this requirement be revised to "For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed the contractual rights of the Transmission Service Provider of that ATC path." c. M10: This measure corresponds to R8, which stipulates the use of a specific algorithm. However, M10 provides the requirement for certain accuracy, which leads to the following questions: i. Is R8 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm? ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M10) to determine if the algorithm and its settings have been properly used. iii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure. d. M11: Same comment on M10 also applies here for R9. | No | Those requirements (at least R5 and R6) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable operation. | No | missing more of them, and so on with a Severe be assigned if the majority of the subrequirements in both R3.1 and R3.2 are missing. Better still, the SDT may consider rearranging R3 so that they can better facilitate VSL development. d. R4: Similar comments in R3 also apply here. In this case, modeling reservations' sources or sinks is used as the parameter to assign progressive VSLs, leaving the violation of either R4.1 or R4.2 or failure to include firm transmission service (a part of R4.3) as the condition for a Severe. It appears that the impact of violation has been applied in arriving at the assigned VSLs, which is not proper. We suggest a rework of this set of VSL so that they are dependent on the extent to which the 3 subrequirments are violated. If necessary, the SDT may want to consider splitting R4.3 to separate out the inclusion of firm reservations requirement to make it a condition for assessing VSLs. e. R5: We do not agree that the VSL should be a single "Severe". R5 contains 3 subrequirements. Presumably, a TSP may fail one or more of these subrequirements. A progressive (graded) VSL should be developed. f. R6: We assess that | None |

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| | | | | | | | | | | R6.1 and R6.2 are parts of a single process requirement. However R6.3 and R6.4 are distinct requirements that need to be met as well. Presumably, a TSP may fail anyone or more of the 3 subrequirements (R6.1 and R6.2 as a unit). Again, a progressive (graded) approach would be more appropriate. We suggest the SDT to revise the VSL for this requirement. g. R7: the second "OR" under the Severe column should be "AND" since the first two conditions both mean that the TOP fails R7.1 completely, but it's only a part of R7. It needs to also fail R7.2 completely to have a Severe failure. To cover for case where the TOP fails either R7.1 or R7.2 completely but not both, the conditions under High may be revised to remove the "but not been more than" parts and include the "did not provide…" as an OR condition. h. R8: We would assume the "M9" referenced in this set of VSL really meant "M10", or else these VSLs would be difficult to understand since R8 is on using the algorithm, not on the values whereas M9 is for R7 that stipulates the requirement for establishing TTC values. Please also see our comments on M10 under Q1. i. R9: Same comment as in VSLs for R8, | |

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| | | | | | | | | | | except in this case the “M10” should be “M11”. Please also see our comments on M11 under Q1. | |
| | Individual | Alessia Dawes | Hydro One Networks | | | Measures M10 and M11 introduce requirements. Requirement 4.1, the "its" before ATCID should be replaced with "the Transmission Service Provider's". Same change to measure M4. Requirement 6.4, we suggest a following revision due to the fact that we cannot be sure "who owns the contractual rights, "For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit the TTC to respect the contractual rights on that ATC Path." | No | R3, R5 and R6 should be assigned Medium since TTCs set the reliability boundary. There is a risk of unreliable operation of the BES when failing to establish TTCs result in the TSP over-selling transmission services beyond the reliability bonds. | No | Note R1 has 5 sub-requirements, not four. In the VSL's for R1 include the statement, "Any violation or violations of the sub-requirements of R1.5 shall be considered a single violation of R1.5. The Lower VSL contains older wording and should be updated to similar wording as the rest of the levels: "The TSP has an ATCID but it is missing x of the five required elements in R1. The VSLs for R2 should be graded based on % to cater to different size systems. Also what is the logic behind using voltage 161 kV in the severe level? The VSLs for R3 should also be graded based on %. Correct VSLs for R8 and R9 with the correct reference to their Measures. | We question the retirement of standards FAC-012 and FAC-013 as indicated in the implementation plan as those FAC standards pertain to different responsible entities than these MOD standards. |
| | Group | | | MRO NERC Standards Review Subcommittee | Tom Mielnik | 1. The MRO believes that R1.3 should be revised to delete the word "Any" from the phrase "Any contractual obligations…". This use of "Any" seems to be unnecessary and may result in over-the-top auditing. 2. The MRO believes the words "all of" should be deleted from R2, "any" from R3.1, "all" from R3.1.3, "any" from R3.2, "all" from R3.2.3, "all of" from R4, "all" from R4.1, "any" from R4.2, "all" and "any" from R4.3, "all" from R6.3, the two uses of "any" in the OSf, and the two uses of "any" in OSnf. The MRO believes the use of these words are unnecessary and may lead to over-the-top auditing. We believe | Yes | The MRO commends the SDT on revising the VRFs to Lower. We believe the revised VRFs are in-line with the NERC | Yes | | 1. The MRO continues to have issues with the overall approach on this standard in combination with the MOD-030. As previously indicated in prior comment periods, the MRO has Transmission Service Providers that manage the levels of transmission service to a reliable level with flowgates and then establishes border control area-to-control area flows to contract path levels so that contractual rights are not exceeded. The MRO reads the MOD-028 standard to require the application of the MOD-028 methodology for its control area-to-control area path postings while MOD-030 standard is used for the flowgates postings. The MRO understands from a discusion with a member of the SDT that in actuality the intent is that the MOD-030 would be used for flowgate calculations and that these quantities could be converted into the ATC path quantities for the control area to control area paths from border companies to outside the Transmission Service Providers area. This application of the flow gate methodology to possibly generate all postings for a Transmission Service Provider including drive out is not clear from the standards and should be clarified in MOD-030 and possibly MOD-028. 2. The MRO commends the SDT in making significant changes to this standard and reissuing it for comment. The MRO believes the eventual standard that is approved will serve the industry and customers better as a result. 3. The MRO believes that |

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| | | | | | | that the Measures, Compliance, and the VSLs should be changed to match these changes to the requirements. 3. The MRO urges the SDT to delete the new measures M10, M11, M12, and M13. We believe that these new measures are micromanagement of the Transmission Service Provider and encourage over-the-top auditing. The MRO considers these measures as written as being "deal-killers". | | definitions of the VRF levels. | | | the first time you use an abbreviation or acronym, you must spell out the full term followed by the abbreviation or acronym in brackets. Subsequent use of the term is then made by its abbreviation or acronym. ex: "Each Transmission Operator shall select one Available Transfer Capability (ATC) methodology2 for calculating ATC (Area Interchange methodology, Rated System Path methodology) or Available Flowgate Capacity (AFC) (Flowgate methodology) for each ATC Path per time period identified in R2 for those Facilities within its Transmission Operator Area." |
| | | | | | | The Area Interchange Methodology Definition, like Rated System Path and Flowgate, includes the text: "Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability." This text descrives the derivation of ATC or AFC, and should not be part of a definition to differentiate between the AIM, RSP and Flowgate methods. R2.1 - I support allowing "Equivalent representation of radial lines and facilities 161 kV or below, but equivalences for elements of the regionally defined definition of the BES should be explained in the ATCID. R6.1 - This requirement and the associated footnote 1 provide that "The Transmission operator may honor distribution factors les than 5% if desired." MOD-29 and MOD-30 have similar language allowing use of alternative distribution factors, generally related to the use of TLR curtailment thresholds. These practices should be posted in the TSP's ATCID and coordinated with the applicable RC (s) and each adjacent TOP and TSP. R8 and R9 – Definition of "GF" Grandfathered Firm/Non-Firm Transmission Service – | | | | | |

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| | Individual | Allen Mosher | American Public Power Association | | | please delete “accepted by FERC” after “Safe Harbor Tariff.” FERC regulatory approval of a tariff for rate purposes is not relevant to what form of transmission service tariff a NERC TSP provides. Many utilities U.S. utilities that are not FERC jurisdictional for electric rate purposes. All Canadian TSPs are non-jurisdictional. R10 and R11 - Postbacks and counterflows: “Counterflows” should be a defined term. It is used in MOD-1, MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-28-1 R10, for example, reads: “counterflowsF are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.” This definition does not in any way describe what a counterflow is. “Postbacks” should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: “Postbacks [Firm][Non-Firm] are changes to firm [non-firm] ATC [AFC] due to a change in the amount of Firm [non-firm] Transmission Service reserved or scheduled for a period, as defined in Business Practices. Postbacks are generally a positive quantity.” Also, include Postbacks in the "e.g." list of factors in M12 and M13. | Yes | | Yes | Major improvement. We will want to refine in the future but good work here. | These comments apply equally to MOD-1, MOD-28. MOD-29 and MOD-30 Excellent work by the SDT. |
| | | | | | | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company is concerned about the risk of ERCOT being found in non-compliance with | | | | | |

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| | Individual | Rex McDaniel | Texas-New Mexico Power Company | | | the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). | Yes | | Yes | | This standard should not apply to ERCOT for the reason stated in Question 1. |
| | Individual | Aaron Staley | Orlando Utilities Commission | | | | Yes | | Yes | | All the requirements and measures look great. One question on R8 and R9. In R8 and R9, it is obviously required that ETC is determined using only the inputs specified, however is it necessary to determine each of the individual inputs and then sum them to get ETC? For example the method for determining ETC might take into account only those items and their effect on the path, but may not break them out into their individual values (NITS, GF, PTP, OS) due to the nature of the method. |
| | Individual | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | | | | | | | | Brazos Electric believes that the concept of a Area Interchange Methodology is not applicable to a single-control area operation like ERCOT. To address this issue, the Applicability section could be modified to state that only TOPs or TSPs that conduct area to area operations and hence have responsibility for ATC Path(s) must have an Area Interchange Methodology. |
| | | | | | | MOD-028 incorporates the new MOD-001 definition of "ATC Path." Please see the NYISO's comments on MOD-001 for an explanation of why this defined term appears to be overly broad when applied to the NYISO and could subject it to obligations, and potential penalties, that would be inconsistent with both the character of the NYISO's FERC-approved financial transmission service model and with waivers from the OASIS posting requirements that FERC has granted the NYISO. In particular, under R5 (and M7) of MOD-028, the current definition of ATC Path could be interpreted to require the NYISO to post TTCs for periods of time further in the future than one day-ahead for interfaces or scheduled lines for which FERC does not require the NYISO to post TTC beyond one-day ahead. As the NYISO discussed in its response to MOD-001, subjecting the NYISO to such requirements would serve no reliabilty purpose. The NYISO has proposed a revision to MOD-001 to address | | | | | |

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| | | | | | | this concern. In the same vein, the SDT should revise R 3.2, R5, and R.7 to clarify that they do not require Transmission Operators to calculate (or establish) monthly ATCs (or TTCs) to the extent that they are not required under FERC's regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead The NYISO has previously commented that MOD-028 should be revised so that TTC would not have to be re-established (or re-calculated) at set intervals when the underlying inputs to TTC have not changed. The SDT previously made a similar change to the ATC re-calculation frequency requirement of what is now R8 under MOD-001 but has not yet made the corresponding change to MOD-028. The NYISO therefore respectfully renews its request that the STD make the requested changes to MOD-028. Under the NYISO system, TTC values do not change often. Accordingly, the proposed MOD-028 requirements would force the NYISO to adopt costly compliance measures that would offer no benefit to its customers and serve no reliability purpose. The NYISO has previously commented that it is critically important to it that the algorithm for calculating "Existing Transmission Commitments" ("ETC") in MOD-028 (and -029) be interpreted flexibly. The NYISO's existing ATC calculation procedure, which reflects the nature of its financial reservation system, and which has been accepted by the Commission, is to calculate firm and non-firm ATC as follows. ATC(Firm) = TTC – Transmission Flow Utilization(Firm) – TRM ATC(Non-Firm) = ATC | | | | | |

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| | Individual | Rick Gonzales | New York Independent System Operator | | | (Firm) – Transmission Flow Utilization(Non-Firm) Where "Transmission Flow Utilization" represents the security constrained network powerflow solutions of the NYISO's Security Constrained Unit Commitment software, with respect to the NYISO Day-Ahead Market, or its Real-Time Commitment and Real-Time Dispatch software with respect to the NYISO's Real-Time Market. As the NYISO has explained in prior comments, it believes that the central role that Transmission Flow Utilization plays in its ATC/TTC calculations can be accommodated under proposed MOD-028 and MOD-029 by accounting for it in the ETC calculation algorithms established under R8 and R9. Specifically, the SDT's proposed definition of the OS(F) variable appears to be broad enough to encompass Transmission Flow Utilization. The NYISO has previously requested that the SDT clarify or revise the OS (F) definition so that it would clearly allow the NYISO to account for Transmisison Flow Utilization in this way. The SDT has not yet responded. Accordingly, the NYISO requests that the the OS(F) definition under R8 be revised to read: OS(F) is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID, including security constrained network powerflow solutions produced by market software used by Transmisison Service Providers that administer FERC-approved organized markets. Similarly, the OS(F) definition under | | | | | | | |

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| | | | | | | R9 should be revised to read: OS(F) is the non-firm capacity reserved for any other service (s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID, including security constrained network powerflow solutions produced by market software used by Transmisison Service Providers that administer FERC-approved organized markets. Making these revisions should have no impact on the vast majority of Transmission Service Providers, because they will neither administer FERC-approved organized markets nor use Transmission Flow Utilization in their ATC/TTC calculations. On the other hand, it would permit the NYISO to come into compliance with NERC's proposed MOD standards without having to make fundamental changes to its FERC-approved market design or financial reservation transmission model. Order No. 890 was clear that it would not require fundamental changes to ISO/RTO market designs. This principle was recently upheld when FERC accepted the NYISO's Order No. 890 tariff compliance filing without requiring any changes to financial reservation transmission model. The NYISO asks that the SDT make the required revision in order to elimiante any possibility of a conflict between the NYISO's FERC approved system and the NERC MOD standards. The NYISO recognizes that the definition of OS(F) may already be broad enough to accommodate Transmission Flow Utilization. If the SDT does not make the | | | | | |

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| | | | | | | requested revision the NYISO will take the position that it may describe its use of Transmission Flow Utilization in the ETC calculation within its ATCID. Nevertheless, because this issue is so important to the NYISO's future compliance with NERC's MOD standards the NYISO would strongly prefer that the issue be expressly addressed within the text of MOD-028 and (MOD-029). The NYISO may raise the issue at FERC if it is not addressed by NERC. | | | | | |

**Consideration of Comments on Draft Standard — MOD-028 — Project 2006-07**

The ATC Standards Drafting Team thanks all commenters who submitted comments on the draft standard MOD-028-1 – Area Interchange Methodology. This standard was posted for a 30-day public comment period from April 16, 2008 through May 15, 2008. The stakeholders were asked to provide feedback on the standard through a special electronic Standard Comment Form. There were more than 24 sets of comments, including comments from more than 75 different people from approximately 50 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

There were some comments that led the drafting team to modify language to improve clarity, but none of the changes made by the drafting team changed the scope or intent of the requirements in the standard.

**Applicability**

- Transmission Operator or Transmission Service Provider - Some entities requested that either the Transmission Operator or the Transmission Service Provider be applicable. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.

- Several entities expressed concern regarding the responsibilities of the Transmission Operator. The SDT interprets the Functional Model as requiring the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. For those entities who believe the TSP to be the appropriate entity, we reiterate that options for delegation of this task exist.

- Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

**Definitions**

- Some entities expressed concerns with the definitions of Counterflows and Postbacks. The SDT does not believe that further definitions are necessary.

**Requirements**

- R2.1 - Some entities questioned the use of the 161kV threshold, requesting either a lower threshold or a requirement to document reasons for using equivalences. The SDT suggested that if such requirements are desired, the commenter should submit a request for a regional standard.

- R6.4 - Some entities expressed concern regarding the assertion that a Transmission operator will have a contractual allocation of rights on a jointly owned or allocated facility. The drafting team modified the standard to refer to the Transmission Service Provider's contractual rights.

**Measures**

- M10 and M11 - Some entities expressed concern with the measures associated with the ETC calculation. The drafting team developed these measures so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measures and associated VSLs from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to its documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation of the whether an entity is compliant. In response to concerns with data retention, the SDT has modified the data retention and the measure. The data retention now states that data to demonstrate compliance with hourly ETC calculations must be retained for 14 days, for daily calculations must be retained for 30 days, and for monthly calculations must be retained for 60 days. The measure has been rephrased to clarify that the intent is to verify that the algorithm was used.

**Compliance Elements**

- Some commenters suggested that some of the VRF's should be raised. The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R5 and R6 do not directly affect the electrical state or the capability of the bulk power system.

- Some commenter's expressed concern with potential for multiple violations of the standard due to a single event. The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.

- Some suggestions were made to change specific VSLs and make them more graded. The SDT modified VSLs for R2, R3, R4, R5, and R7. Two measures were modified as well to correct invalid references.

- Some suggestions were made to modify the VSLs for R2 and R3 so they are based on a % rather than fixed counts. Variations in determining what constitutes the facilities that enter into the denominator would make this a difficult item to calculate, with significant discretion in determining the percentage. Because of this difficulty in measuring the value, the SDT believe it is appropriate to leave the numbers in the VSLs as fixed counts.

**Concepts**

- Several entities identified a concern with requiring "all" or "any" data. The SDT clarified that providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC.

- The NERC RTOSDT expressed concern that the standard does not refer to Planning an operating limits. The SDT directed the RTOSDT to the specific areas in the methodology standard where such reference rare made.

**Variances**

Several entities have continued to express concern regarding the applicability of the ATC, TRM, and CBM standards. While the drafting team has attempted to write the standards in ways that are flexible and allow for organizational diversity, we note that FERC Order 890 makes reference to the use of Variances. Entities with non-traditional physical transmission markets or that have alternative ATC methodologies that meet or exceed the NERC ATC standards may wish to consider requesting one or more Variances related to these standards.

The SDT believes it may be helpful to the industry to review the process for Variances. The Variance process can work either concurrent with or independent of the development of a standard. Because the drafting team working on a particular standard is likely to already have the necessary expertise to participate in the development of the Variance, concurrent development is generally more efficient. However, this may not always be practical; in this case, standards drafting may proceed, and even complete, prior to the development and approval of Variances. In this case, entities should seek to develop those Variances and seek their approval prior to the effective date of the standard. An entity is not exempt from meeting the requirements of the standard if the effective date has passed and that entity is in the process of developing a Variance.

The NERC process allows for three different types of variances:

- An Entity Variance
- A Regional Variance less than an Interconnection
- A Regional Variance on Interconnection-Wide basis

The NERC Rules of Procedure describe an Entity Variance as follows:

> Entity Variance — Any variance from a NERC reliability standard that is proposed to apply to one entity or a subset of entities within a limited portion of a regional entity, such as a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users, shall be approved through the regular standards development process defined in the NERC Reliability Standards Development Procedure and shall be made part of the applicable NERC reliability standard.

Entities seeking an Entity Variance should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requester is addressing the reliability goals of the standard. The ballot body is comprised of any member of the Registered Ballot Body that is interested and registers to join the ballot pool. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe a Regional Variance Less Than an Interconnection as follows:

> Any regional variance from a NERC reliability standard that is proposed to apply for a regional entity, but not for an interconnection, shall be approved through the NERC Reliability Standards Development Procedure, except that only members of the registered ballot body located in the affected interconnection shall be permitted to vote; and the variance shall be made part of the applicable NERC reliability standard.

Entities seeking a Regional Variance Less Than an Interconnection should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requestor is addressing the reliability goals of the standard. The ballot body is comprised of any interested entities that that have registered with NERC and is a user, owner, or operator of facilities located within the interconnection in which the region requesting the Variance is located. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe an Regional Variance on an Interconnection-wide Basis as follows:

> An interconnection-wide regional variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the NERC reliability standard. NERC shall rebuttably presume that a regional variance from a NERC reliability standard that is developed, in accordance with a procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Entities seeking a Regional Variance on an Interconnection-wide Basis should draft that Variance using the regional standards development process described in the region's delegation agreement. In that Variance, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Once approved through the regional standards development process, the Variance should be brought to NERC for filing with the appropriate regulatory authorities.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving these standards forward to posting for pre-ballot review.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standard can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

## Index to Questions, Comments, and Responses



[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Thad Ness | AEP | x | | x | | x | x | | | | |
| 2. | Anita Lee (G3) | AESO | | x | | | | | | | | |
| 3. | Helen Stines (G1) | Alcoa Power Generating, Inc. | x | | x | | | | | | | |
| 4. | Ken Goldsmith (G7) | ALTW | | | | x | | | | | | |
| 5. | Eugene Warnecke (G1) | Ameren | x | | x | | | | | | | |
| 6. | Allen Mosher | American Public Power Association | x | | | x | | x | | | | |
| 7. | Dave Rudolph (G7) | Basin Electric Power Co | x | | x | | x | x | | | | |
| 8. | Chris Bradley (G1) | Big Rivers Electric Cooperative | x | | x | | | | | | | |
| 9. | Denise Koehn (G6) | Bonneville Power Administration | x | | x | | x | x | | | | |
| 10. | Mike Viles (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 11. | Abbey Nulph (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 12. | Don Watkins (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 13. | Patrick Roechelle (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 14. | Kammy Rogers-Holiday (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 15. | Robin Chung (G6) | Bonneville Power Administration | | | x | | x | x | | | | |
| 16. | Rebecca Berdahl (G6) | Bonneville Power Administration | | | x | | | | | | | |
| 17. | Susan Millar (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 18. | Todd Miller (G6) | Bonneville Power Administration | | | x | | x | x | | | | |
| 19. | Elizabeth Loebach (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 20. | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | x | | | | x | | | | | |
| 21. | Brent Kingsford (G3) | California ISO | | x | | | | | | | | |
| 22. | Paul Bleuss (G5) | California ISO | | x | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 23. | Paul Rocha | CenterPoint Energy | x | | | | | | | | | |
| 24. | Don Reichenbach (G1) | Duke Energy - Carolinas | x | | x | | | | | | | |
| 25. | Greg Rowland | Duke Energy Corporation | x | | x | | x | x | | | | |
| 26. | Jim Case (G5) | Entergy Services, Inc. | x | | | | | | | | | |
| 27. | Joachim Francois (G1) | Entergy Services, Inc. | x | | x | | | | | | | |
| 28. | Jack Cashin/Barry Green | EPSA | | | | | x | x | | | | |
| 29. | H. Steven Myers (G3) (G5) (I) | ERCOT ISO | | x | | | | | | | | |
| 30. | Ralph Anderson (G5) | FMPA | | | | x | | | | | | |
| 31. | Earl Fair | Gainesville Regional Utilities | x | | x | | x | | | | | |
| 32. | Ross Kovacs (G1) | Georgia Transmission Corp. | x | | | | | | | | | |
| 33. | Joe Knight (G7) | GRE | x | | x | | x | x | | | | |
| 34. | David Kiguel (G4) | Hydro One Networks | x | | x | | | | | | | |
| 35. | Alessia Dawes | Hydro One Networks | x | | x | | | | | | | |
| 36. | Roger Champagne (G4) | Hydro Quebec TransEnergie | x | x | | | | | | | | |
| 37. | Ron Falsetti (G3) (I) | IESO | | x | | | | | | | | |
| 38. | Kathleen Goodman (G4) | ISO-New England | | x | | | | | | | | |
| 39. | Jim Useldinger | Kansas City Power & Light | x | | | | | | | | | |
| 40. | Eric Ruskamp (G7) | LES | x | | x | | x | x | | | | |
| 41. | Joe DePoorter (G7) | MGE | | | x | x | x | x | | | | |
| 42. | Bill Phillips (G3) | MISO | | x | | | | | | | | |
| 43. | Terry Blke (G7) | MISO | | x | | | | | | | | |
| 44. | Jason Marshall (G5) | MISO | | x | | | | | | | | |
| 45. | Carol Gerou (G7) | MP | x | | x | | x | x | | | | |
| 46. | Larru Brusseau (G7) | MRO | | | | | | | | | | x |
| 47. | Michael Brytowski (G7) | MRO | | | | | | | | | | x |
| 48. | Tom Mielnik (G7) | MRO NERC Standards Review Subcommittee | x | | x | | x | x | | | | |
| 49. | Jerry Tang (G1) | Municipal Electric Auth. of GA | x | | x | | | | | | | |
| 50. | Jim Case, Chair (G5) | NERC RTOSDT | x | x | | x | | | | | | |
| 51. | Greg Campoli (G4) | New York ISO | | x | | | | | | | | |
| 52. | Ralph Rufrano (G4) | New York Power Authority | x | | | x | x | x | | | x | |
| 53. | Al Adamson (G4) | NYSRC | | | | | | | | | | x |
| 54. | Rick White (G4) | Northeast Utilities | x | | | x | | | | | | |
| 55. | Guy V. Zito (G4) | NPCC | | | | | | | | | | x |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 56. | Jim Castle (G3) | NYISO | | x | | | | | | | | |
| 57. | Greg Ward / Darryl Curtis | Oncor Electric Delivery | x | | | | | | | | | |
| 58. | Ron Falsetti | Ontario IESO | | x | | | | | | | | |
| 59. | Aaron Staley | Orlando Utilities Commission | x | | x | | x | | | | x | |
| 60. | Richard Kafka | Pepco Holdings, Inc. | x | | x | | x | x | | | | |
| 61. | Patrick Brown (G3) (I) | PJM | | x | | | | | | | | |
| 62. | Al DiCaprio (G5) | PJM | | x | | | | | | | | |
| 63. | Phil Creech (G1) | Progress Energy - Carolinas | x | | x | | | | | | | |
| 64. | Phil Riley | Public Service Commission of South Carolina | | | | | | | | | x | |
| 65. | Pat Huntley (G1) | SERC | | | | | | | | | | x |
| 66. | John Troha (G1) | SERC | | | | | | | | | | x |
| 67. | Vicky Budreau (G1) | So. Carolina Public Service Auth. | x | | x | | | | | | | |
| 68. | Al McMeekin (G1) | South Carolina Electric & Gas | x | | x | | | | | | | |
| 69. | Stan Shealy (G1) | South Carolina Electric & Gas | x | | x | | | | | | | |
| 70. | Jim Griffith (G1) | Southern Co. | x | | x | | | | | | | |
| 71. | DuShaune Carter (G1) | Southern Co. | x | | x | | | | | | | |
| 72. | Charles Young (G3) | Southwest Power Pool | | x | | | | | | | | |
| 73. | Rex McDaniel | Texas-New Mexico Power Company | x | | | | | | | | | |
| 74. | Doug Bailey (G1) | TVA | x | | x | | | | | | x | |
| 75. | Jim Haigh (G7) | WAPA | x | | | | | x | | | | |
| 76. | Neal Balu (G7) | WPS | | | x | x | x | x | | | | |
| 77. | Pam Oreschnick (G7) | Xcel | x | | x | | x | x | | | | |

I — Individual
G1 — SERC Available Transfer Capability Working Group
G3 — ISO RTO Council/Standards Review Committee (SRC)
G4 — NPCC Regional Standards Committee
G5 — NERC RTO SDT
G6 — BPA
G7 — MRO Standards Review Committee

1. **The drafting team modified some requirements and associated measures in MOD-028 to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct. Incorrect Requirement(s) or Measure(s):**

**Summary Consideration:**

Some entities requested that either the Transmission operator or the Transmission Service Provider be applicable. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate.

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

Some entities questioned the use of the 161kV threshold, requesting either a lower threshold or a requirement to document reasons for using equivalences. The SDT suggested that if such requirements are desired, the commenter should submit a request for a regional standard.

Some entities expressed concern with the measures associated with the ETC calculation. The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation. In response to concerns with data retention, the SDT has revised the data retention so that for hourly ETC calculations, 14 days of evidence must be retained – for daily ETC calculations 30 days of evidence must be retained – and for monthly ETC calculations, 60 days of data must be retained. The drafting team also modified the language in Measures M10 and M11 to clarify that the measure is verifying that the TSP used the algorithm in the requirement to calculate ETC.

R6.4 - Some entities expressed concern regarding the assertion that a Transmission operator will have a contractual allocation of rights on a jointly owned or allocated facility. The drafting team modified the standard to refer to the Transmission Service Provider's contractual rights.

Several entities identified a concern with requiring "all" or "any" data. The SDT clarified that providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC.

Some entities expressed concerns with the definitions of Counterflows and Postbacks. The SDT does not believe that further definitions are necessary.

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| EPSA | Through this revision process, some of the MOD standards have included an explicit requirement for consistency between planning assumptions and modeling assumptions used in calculation of ATC. We believe this is appropriate and should be included in MOD 028. |
| **Response:** This requirement is located in MOD-001 which applies to MOD-028, MOD-029 and MOD-030. | |
| Kansas City Power & Light | The Transmission Service Provider should be added along with TOP to perform these functions in all requirements |
| Response: Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. | |
| ERCOT ISO | Requirement 1:I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining TTC:<br><br>Requirement 2:I suggest modifying the requirement to state: "When calculating TTC for ATC Paths, the Transmission Operator with ATC Path(s) shall use a Transmission model that contains all of the following:<br><br>Requirement 3:I suggest modifying the requirement to state: "When calculating TTCs for ATC Paths, the Transmission Operator with ATC Path(s) shall include the following data for the Transmission Service Provider's area. The Transmission Operator with ATC Path(s) shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed<br><br>Requirement 4:I suggest modifying the requirement to state: "When calculating TTCs for ATC Paths, the Transmission Operator with ATC Path(s) shall meet all of the following conditions :"Requirement 5:I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) shall establish TTC for each ATC Path as defined below:<br><br>Requirement 6:I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) shall establish TTC for each ATC Path using the following process:<br><br>Requirement 7:I suggest modifying the requirement to state: "The Transmission Operator with ATC Path(s) shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: "Requirement 8:I suggest modifying the requirement to state: "When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETCF) for all time periods for an ATC Path the Transmission Service Provider with ATC Path(s) shall use the following algorithm: |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | Requirement 9:I suggest modifying the requirement to state: "When calculating ETC for non-firm commitments (ETCNF) for all time periods for an ATC Path the Transmission Service Provider with ATC Path(s) shall use the following algorithm:<br><br>Requirement 10:I suggest modifying the requirement to state: "When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider with ATC Path(s) shall utilize the following algorithm: "Requirement 11:I suggest modifying the requirement to state: "When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider with ATC Path(s) shall use the following algorithm:" |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| NPCC Regional Standards Committee | a. R4.1: The "its" before ATCID should be replaced with "the" or "the Transmission Service Provider's" since the ATCID is the TSP's document. Same change to M4.<br>**Response:** The Drafting Team has modified the language as suggested.<br><br>b. R6.4: In general, a TOP doesn't have contractual rights of a jointly-owned or allocated facility, whereas the TSP does. We suggest this requirement be revised to "For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed the contractual rights of the Transmission Service Provider of that ATC path."<br>**Response:** The Drafting Team has modified R6.4 as follows: "R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights."<br><br>c. M11: Same comment on M10 also applies here for R9<br>**Response:** No comment was listed for M10 to reply or to apply to M11. |
| **Response:** Please see in-line responses. | |
| Duke Energy Corporation | R1 — Need to ensure that comparable information should be required in either the study report or the ATCID in MOD-028, MOD-029 and MOD-030. |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | **Response:** The MOD-028 and MOD-030 standards have requirements for information to be located in the ATCID. MOD-029 has requirements for the comparable information to be included in the resulting study report. The SDT has reviewed and confirmed that the requirements are equivalent across the methodologies.<br><br>R2.1 — Bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on TTC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders.<br>**Response:** The Drafting Team notes that the language of R2.1 allows detailed modeling of 161 kV and below; the language does not require it. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. Requirements for Data Exchange in MOD-001 already address sharing of models to support reliability objectives; to the extent a reliability entity has concerns regarding the use of equivalences within the model, the SDT encourages those entities to work directly with each other. Disclosure of this information to Transmission Customers should be addressed through the use of the NAESB process. |
| **Response:** Please see in-line responses. | |
| Oncor Electric Delivery | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| Gainesville Regional Utilities | In R8&9, must you determine ETC by only using the inputs specified, or can you determine each one separately then sum them to get ETC? Some methods for determining ETC may not take into account each individual item and its effect on a given path. |
| **Response:** The equations in R8 and R9 describe the components that must be considered in ETC, but do not dictate the process by which the | |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| value is calculated. | |
| IRC Standards Review Committee | a. R4.1: The "its" before ATCID should be replaced with "the" or "the Transmission Service Provider's" since the ATCID is the TSP's document. Same change to M4.<br>**Response:** The Drafting Team has modified the language as suggested.<br><br>b. R6.4: In general, a TOP doesn't have contractual rights of a jointly-owned or allocated facility, whereas the TSP does. We suggest this requirement be revised to ?For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed the contractual rights of the Transmission Service Provider of that ATC path.?<br>**Response:** The Drafting Team has modified R6.4 as follows: "R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights."<br><br>c. M10: This measure corresponds to R8, which stipulates the use of a specific algorithm. However, M10 provides the requirement for certain accuracy, which leads to the following questions:<br>i. Is R8 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm?<br>ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M10) to determine if the algorithm and its settings have been properly used.<br>iii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure.<br><br>d. M11: Same comment on M10 also applies here for R9.<br>**Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to its documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | allow for subjective interpretation. The drafting team modified the language in Measures M10 and M11 to clarify that the measure is verifying that the TSP used the algorithm in the requirement to calculate ETC. |
| **Response:** Please see in-line responses. | |
| Ontario IESO | 1. We offer the following comments/suggestions:<br>a. R4.1: The "its" before ATCID should be replaced with "the" or "the Transmission Service Provider's" since the ATCID is the TSP's document. Same change to M4.<br>**Response:** The Drafting Team has modified the language as suggested.<br><br>b. R6.4: In general, a TOP doesn't have contractual rights of a jointly-owned or allocated facility, whereas the TSP does. We suggest this requirement be revised to ?For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Operator so the TTC does not exceed the contractual rights of the Transmission Service Provider of that ATC path.?<br>**Response:** The Drafting Team has modified R6.4 as follows: "R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights."<br><br>c. M10: This measure corresponds to R8, which stipulates the use of a specific algorithm. However, M10 provides the requirement for certain accuracy, which leads to the following questions:<br>i. Is R8 about the use of an algorithm only or is it also about the proper or consistent setting of the variables within that algorithm?<br>ii. If it is also the proper or consistent setting of the variables, the requirement should stipulate the conditions rather than leaving the assessment to a recalculation process (stipulated in M10) to determine if the algorithm and its settings have been properly used.<br>iii. If accuracy is to be a criterion for having proper and consistent setting of the variables, it becomes a requirement and hence should be stipulated in the requirement section, not in the measure. d. M11: Same comment on M10 also applies here for R9.<br>**Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation. The drafting team modified the language in Measures M10 and M11 to clarify that the measure is verifying that the TSP used the algorithm in the requirement to calculate ETC. |
| **Response:** Please see in-line responses. | |
| Hydro One Networks | Measures M10 and M11 introduce requirements.<br>**Response:** The drafting team developed this measure so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to their documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation. The drafting team modified the language in Measures M10 and M11 to clarify that the measure is verifying that the TSP used the algorithm in the requirement to calculate ETC.<br><br>Requirement 4.1, the "its" before ATCID should be replaced with "the Transmission Service Provider's". Same change to measure M4.<br>**Response:** The Drafting Team has modified the language as suggested.<br><br>Requirement 6.4, we suggest a following revision due to the fact that we cannot be sure "who owns the contractual rights, "For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit the TTC to respect the contractual rights on that ATC Path."<br>**Response:** The Drafting Team has modified R6.4 as follows: "R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights." |
| **Response:** Please see in-line responses. | |
| MRO | 1. The MRO believes that R1.3 should be revised to delete the word "Any" from the phrase "Any contractual obligations?". This use of "Any" seems to be unnecessary and may result in over-the-top auditing.<br>**Response:** Providing only "some" of the data would not accomplish the reliability goal of sharing information |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | transparently for the purposes of improving ATC. Use of the words of "any" and "all" prevents discretionary sets of data being provided and argued as being compliant.<br><br>2. The MRO believes the words "all of" should be deleted from R2, "any" from R3.1, "all" from R3.1.3, "any" from R3.2, "all" from R3.2.3, "all of" from R4, "all" from R4.1, "any" from R4.2, "all" and "any" from R4.3, "all" from R6.3, the two uses of "any" in the OSf, and the two uses of "any" in OSnf. The MRO believes the use of these words are unnecessary and may lead to over-the-top auditing. We believe that the Measures, Compliance, and the VSLs should be changed to match these changes to the requirements.<br>**Response:** Providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of "any" and "all" prevents discretionary sets of data being provided and argued as being compliant.<br><br>3. The MRO urges the SDT to delete the new measures M10, M11, M12, and M13. We believe that these new measures are micromanagement of the Transmission Service Provider and encourage over-the-top auditing. The MRO considers these measures as written as being "deal-killers".<br>**Response:** The drafting team developed measures M10 and M11 so that a benchmark could be developed to verify that an entity's processes for calculating ETC are functioning correctly. The measure and associated VSL from the previous draft focused on an entity proving this fact, but the standard did not provide any guidance on how to do so. Additionally, many commenters noted that the VSL was structured as a "pass/fail" VSL, and requested a graded VSL be developed. In response, the SDT developed this approach for identifying how closely an entity's process conforms to its documented process for determining ETC. The SDT focused the measure and VSL on how "repeatable" the process and associated result was after the fact. In effect, the measure is not intended to validate whether the calculated ETC is correct or incorrect, but rather that the process that occurred in the past matches the process documented in the ATCID. Recognizing that it may be difficult to exactly reproduce the conditions, the SDT drafted the measure to allow for a certain amount of difference between the original value and the subsequently calculated value. This is not intended to say that this requirement allows for a certain level of inaccuracy, but rather that the process of reproducing a calculation for auditor review may be difficult to do with absolute precision, given the complexities of the process. The intent of using this measure is to reduce vagueness, and to provide a clear and measurable goal for performance that is unambiguous and does not allow for subjective interpretation. The drafting team modified the language in Measures M10 and M11 to clarify that the measure is verifying that the TSP used the algorithm in the requirement to calculate ETC.<br><br>The reason for the objection to M12 and M13 is not clear. |
| **Response:** Please see in-line responses. | |
| American Public Power Association | The Area Interchange Methodology Definition, like Rated System Path and Flowgate, includes the text: "Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability." |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | This text describes the derivation of ATC or AFC, and should not be part of a definition to differentiate between the AIM, RSP and Flowgate methods.<br>**Response:** The derivation of ATC is part of the Area Interchange Methodology, it is not identical in all three methods and it is appropriate to be included.<br><br>R2.1 - I support allowing "Equivalent representation of radial lines and facilities 161 kV or below, but equivalences for elements of the regionally defined definition of the BES should be explained in the ATCID.<br>**Response:** The Drafting Team notes that the language of R2.1 allows detailed modeling of 161 kV and below; the language does not require it. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. Requirements for Data Exchange in MOD-001 already address sharing of models to support reliability objectives; to the extent a reliability entity has concerns regarding the use of equivalences within the model, the SDT encourages those entities to work directly with each other. Disclosure of this information to Transmission Customers should be addressed through the use of the NAESB process.<br><br>R6.1 - This requirement and the associated footnote 1 provide that "The Transmission operator may honor distribution factors les than 5% if desired." MOD-29 and MOD-30 have similar language allowing use of alternative distribution factors, generally related to the use of TLR curtailment thresholds. These practices should be posted in the TSP's ATCID and coordinated with the applicable RC(s) and each adjacent TOP and TSP.<br>**Response:** Requiring this information to be included in the ATCID will not add to the reliability of the system. Therefore, the Drafting Team does not see the benefit in adding a new requirement for such at this time.<br><br>R8 and R9 — Definition of “GF” Grandfathered Firm/Non-Firm Transmission Service — please delete “accepted by FERC” after “Safe Harbor Tariff.” FERC regulatory approval of a tariff for rate purposes is not relevant to what form of transmission service tariff a NERC TSP provides. Many utilities U.S. utilities that are not FERC jurisdictional for electric rate purposes. All Canadian TSPs are non-jurisdictional.<br>**Response:** The SDT agrees, and has modified R8 and R9 per APPA’s suggestion.<br><br>R10 and R11 — Postbacks and counterflows: “Counterflows” should be a defined term. It is used in MOD-1, MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-28-1 R10, for example, reads: “counterflows” are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.? This definition does not in any way describe what a counterflow is. — “Postbacks” should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: — Postbacks [Firm] [Non-Firm] are changes to firm [non-firm] ATC [AFC] due to a change in the amount of Firm [non-firm] Transmission Service reserved or scheduled for a period, as defined in Business Practices. Postbacks are generally a positive quantity. Also, include Postbacks in |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | the "e.g." list of factors in M12 and M13.<br>**Response:** The SDT has reviewed the standards, and finds that the Postbacks and counterflows definitions, the requirements for the ATCID, and the requirements and measures for calculating ATC in the methodologies address this sufficiently. MOD-001 indicates in the definition that Postbacks are defined by business practices, while the individual methodology standards indicate that Postbacks are "changes to firm (non-firm) ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices." Counterflows is an industry term, and the manner in which it applies to these standards is described in the methodologies ("adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID"), as well as in MOD-001 R3.2.<br>Regarding the use of postbacks in M12 and M13, the examples provided were not intended to be an exhaustive list. |
| **Response:** Please see in-line responses. | |
| Texas-New Mexico Power Company | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| New York Independent System Operator | MOD-028 incorporates the new MOD-001 definition of "ATC Path." Please see the NYISO's comments on MOD-001 for an explanation of why this defined term appears to be overly broad when applied to the NYISO and could subject it to obligations, and potential penalties, that would be inconsistent with both the character of the NYISO's FERC-approved financial transmission service model and with waivers from the OASIS posting requirements that FERC has granted the NYISO. In particular, under R5 (and M7) of MOD-028, the current definition of ATC Path could be interpreted to require the NYISO to post TTCs for periods of time further in the future than one day-ahead for interfaces or scheduled lines for which FERC does not require the NYISO to post TTC beyond one-day ahead. |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | **Response:** The Drafting Team believes that the definition of ATC Path is correct. R1 in MOD-001 requires Transmission Operators to select a methodology based on ATC Paths, which is defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. The SDT understands that while NYISO calculate ATC values on its internal interfaces, those internal interfaces do not meet the definition of an ATC Path, i.e., they are not described by a POR/POD combination and they are not a FERC Posted path.<br><br>Note that NYISO may wish to pursue a Variance to this standard.<br><br>As the NYISO discussed in its response to MOD-001, subjecting the NYISO to such requirements would serve no reliability purpose. The NYISO has proposed a revision to MOD-001 to address this concern. In the same vein, the SDT should revise R 3.2, R5, and R.7 to clarify that they do not require Transmission Operators to calculate (or establish) monthly ATCs (or TTCs) to the extent that they are not required under FERC's regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead The NYISO has previously commented that MOD-028 should be revised so that TTC would not have to be re-established (or re-calculated) at set intervals when the underlying inputs to TTC have not changed.<br><br>The SDT previously made a similar change to the ATC re-calculation frequency requirement of what is now R8 under MOD-001 but has not yet made the corresponding change to MOD-028. The NYISO therefore respectfully renews its request that the STD make the requested changes to MOD-028. Under the NYISO system, TTC values do not change often. Accordingly, the proposed MOD-028 requirements would force the NYISO to adopt costly compliance measures that would offer no benefit to its customers and serve no reliability purpose.<br>**Response:** The requirement in MOD-028 requires entities to 'establish' the TTC on a minimum frequency. 'Establish' was intentionally chosen so that re-calculation would not be required if no inputs have changed, Even for entities that do not sell physical transmission service, the TTC is required data for reliability and the Drafting Team does not see how the defined timeframe for reviewing the TTC would result in an overly burdensome process for NYISO.<br><br>The NYISO has previously commented that it is critically important to it that the algorithm for calculating Existing Transmission Commitments? ("ETC") in MOD-028 (and -029) be interpreted flexibly. The NYISO's existing ATC calculation procedure, which reflects the nature of its financial reservation system, and which has been accepted by the Commission, is to calculate firm and non-firm ATC as follows. ATC (Firm) = TTC ? Transmission Flow Utilization (Firm) — TRMATC (Non-Firm) = ATC (Firm) — Transmission Flow Utilization (Non-Firm) Where "Transmission Flow Utilization" represents the security constrained network powerflow solutions of the NYISO's Security Constrained Unit Commitment software, with respect to the NYISO Day-Ahead Market, or its Real-Time Commitment and Real-Time Dispatch software with respect to the NYISO's Real-Time Market. |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
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| | As the NYISO has explained in prior comments, it believes that the central role that Transmission Flow Utilization plays in its ATC/TTC calculations can be accommodated under proposed MOD-028 and MOD-029 by accounting for it in the ETC calculation algorithms established under R8 and R9. Specifically, the SDT's proposed definition of the OS (F) variable appears to be broad enough to encompass Transmission Flow Utilization. The NYISO has previously requested that the SDT clarify or revise the OS (F) definition so that it would clearly allow the NYISO to account for Transmission Flow Utilization in this way. The SDT has not yet responded. Accordingly, the NYISO requests that the OS (F) definition under R8 be revised to read: OS (F) is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID, including security constrained network powerflow solutions produced by market software used by Transmission Service Providers that administer FERC-approved organized markets. Similarly, the OS(F) definition under R9 should be revised to read: OS (F) is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID, including security constrained network powerflow solutions produced by market software used by Transmission Service Providers that administer FERC-approved organized markets. Making these revisions should have no impact on the vast majority of Transmission Service Providers, because they will neither administer FERC-approved organized markets nor use Transmission Flow Utilization in their ATC/TTC calculations. On the other hand, it would permit the NYISO to come into compliance with NERC's proposed MOD standards without having to make fundamental changes to its FERC-approved market design or financial reservation transmission model. Order No. 890 was clear that it would not require fundamental changes to ISO/RTO market designs. This principle was recently upheld when FERC accepted the NYISO's Order No. 890 tariff compliance filing without requiring any changes to financial reservation transmission model. The NYISO asks that the SDT make the required revision in order to eliminate any possibility of a conflict between the NYISO's FERC approved system and the NERC MOD standards. The NYISO recognizes that the definition of OS (F) may already be broad enough to accommodate Transmission Flow Utilization. If the SDT does not make the requested revision the NYISO will take the position that it may describe its use of Transmission Flow Utilization in the ETC calculation within its ATCID. Nevertheless, because this issue is so important to the NYISO's future compliance with NERC's MOD standards the NYISO would strongly prefer that the issue be expressly addressed within the text of MOD-028 and (MOD-029). The NYISO may raise the issue at FERC if it is not addressed by NERC.<br>**Response:** As NYISO has noted in its comments on MOD-028, the current wording of the Other Service (OS) term is broad enough to cover the NYISO market condition described. In addition, there is a NERC process by which NYISO can request a formal interpretation. |
| **Response:** Please see in-line responses. | |
| PJM | PJM does not have any specific comments. |
| Pepco Holdings, Inc | PHI supports the comments of PJM and will not submit duplicate comments |
| **Response:** PJM did not comment on this question. | |

| Organization/Group | Question 1 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| Bonneville Power | BPA does not believe any are incorrect. |

**2. The drafting team has modified the Violation Risk Factors for MOD-028 to reflect industry concerns that they did not match NERC's VRF definitions. NERC's VRF definitions are listed below. Are the current VRFs established correctly? If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.**

High Risk Requirement:

(a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement:

(a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement: is administrative in nature and

(a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or

(b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

**Summary Consideration:**

Some commenters suggested that some of the VRF's should be raised. The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R5 and R6 do not directly affect the electrical state or the capability of the bulk power system.

| Organization/Group | Question 2: | Question 2 Comments: |
|---|---|---|
| NPCC Regional Standards Committee | No | No, those requirements (at least R5 and R6) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable operation. |
| **Response:** The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R5 and R6 do not directly affect the electrical state or the capability of the bulk power system. | | |

| Organization/Group | Question 2: | Question 2 Comments: |
|---|---|---|
| IRC Standards Review Committee | No | No, those requirements (at least R5 and R6) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable operation. |
| **Response:** The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R5 and R6 do not directly affect the electrical state or the capability of the bulk power system. | | |
| Ontario IESO | No | Those requirements (at least R5 and R6) that hold the TOP responsible for establishing TTCs should be assigned a Medium since TTCs set the reliability boundary, like an SOL or IROL, within which the TSP may provide transmission services. Failure to establish TTCs may result in the TSP over-selling transmission services beyond the reliability bounds, risking the BES to unreliable operation. |
| **Response:** The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R5 and R6 do not directly affect the electrical state or the capability of the bulk power system. | | |
| Hydro One Networks | No | R3, R5 and R6 should be assigned Medium since TTCs set the reliability boundary. There is a risk of unreliable operation of the BES when failing to establish TTCs result in the TSP over-selling transmission services beyond the reliability bonds. |
| **Response:** The Drafting Team disagrees. The majority of the team and the industry believes that a violation of R3, R5 and R6 do not directly affect the electrical state or the capability of the bulk power system. | | |
| PJM | Yes | PJM supports NERC?s position to revise all Violation Risk Factors to have an assigned risk factor of ?Lower.? A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. |
| **Response:** Thank you for your supportive comment. | | |
| MRO? | Yes | The MRO commends the SDT on revising the VRFs to Lower. We believe the revised VRFs are in-line with the NERC definitions of the VRF levels. |
| **Response:** Thank you for your supportive comment. | | |
| Kansas City Power & Light | Yes | |
| SERC ATCWG | Yes | |
| Public Service Commission of South Carolina | Yes | |
| Duke Energy Corporation | Yes | |
| Oncor Electric Delivery | Yes | |
| Bonneville Power | Yes | |

| Organization/Group | Question 2: | Question 2 Comments: |
|---|---|---|
| Gainesville Regional Utilities | Yes | |
| American Public Power Association | Yes | |
| Texas-New Mexico Power Company | Yes | |
| Orlando Utilities Commission | Yes | |
| EPSA | | no comment |

3. The drafting team has modified the Violation Severity Levels for MOD-028 to reflect industry concerns that they were too “pass/fail” oriented. Are the current VSLs established correctly?

**Summary Consideration:**

Some commenters expressed concern with potential for multiple violations of the standard due to a single event. The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.

Some suggestions were made to change specific VSLs and make them more graded. The SDT modified VSLs for R2, R3, R4, R5, and R7. Two measures were modified as well to correct invalid references.

Some suggestions were made to modify the VSLs for R2 and R3 so they are based on a % rather than fixed counts. Variations in determining what constitutes the facilities that enter into the denominator would make this a difficult item to calculate, with significant discretion in determining the percentage. Because of this difficulty in measuring the value, the SDT believe it is appropriate to leave the numbers in the VSLs as fixed counts.

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| PJM | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations — this language to be added to the standard. |
| **Response:** The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events. | | |
| Ontario IESO | No | We suggest the following changes:<br>a. R1: R1.5 contains several subrequirements. It is not clear what constitutes a failure of R1.5 when considering the VSLs for R1 (i.e. number of elements missing in the ATCID. For similar situations in MOD-008, it is stipulated that failing any one of the subrequirements would constitute a requirement failure. We therefore suggest adding a sentence under each of Moderate, High and Severe: ?Any violation or violations of the sub-requirements of R1.5 shall be considered a single violation of R1.5.?<br>**Response:** The SDT agrees and has modified the VSLs for R1.<br>b. R2: We do not agree with the VSL assignments. Note that R2 has 3 subrequirements, hence a Moderate should be assigned for failing 1 of the 3, a High for failing 2 and a Severe for failing all 3. A progressive VSL for R2.3 doesn’t work in this case since even having >30 incorrect ratings, the TOP would have only failed one of the 3 subrequirements and should not be assigned a Severe if it met the other 2. We suggest the SDT to revise these VSLs.<br>**Response:** The SDT agrees and has modified the VSLs for R2.<br><br>c. R3: We do not agree with the VSL assignment. R3 has two subrequirements: R3.1 for on-peak and off-peak intra-day and next-day TTCs, and R3.2 for days two through 31 TTCs and for months two through |

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| | | 13 TTCs. A total failure of R3 would be failing both subrequirements. Within each of the subrequirements, there are 3 subrequirements. While the VSLs for each of R3.1 and R3.2 can be made progressive (graded) according to the extent of missing outages, additions, retirements, and load forecast and unit commitments, etc. they need to eventually be factored in the VSLs for R3. Suggest to revise the VSLs so that a Low would be missing some of the subrequirements in either R3.1 and R3.2, a Moderate for missing more of them, and so on with a Severe be assigned if the majority of the subrequirements in both R3.1 and R3.2 are missing. Better still, the SDT may consider rearranging R3 so that they can better facilitate VSL development.<br>**Response:** The SDT believes the VSLs for R3 are written appropriately, but has modified them slightly to reduce the potential for multiple violations due to a single event.<br><br>d. R4: Similar comments in R3 also apply here. In this case, modeling reservations? sources or sinks is used as the parameter to assign progressive VSLs, leaving the violation of either R4.1 or R4.2 or failure to include firm transmission service (a part of R4.3) as the condition for a Severe. It appears that the impact of violation has been applied in arriving at the assigned VSLs, which is not proper. We suggest a rework of this set of VSL so that they are dependent on the extent to which the 3 subrequirements are violated. If necessary, the SDT may want to consider splitting R4.3 to separate out the inclusion of firm reservations requirement to make it a condition for assessing VSLs.<br>**Response:** The SDT believes the VSLs for R4 are written appropriately, but has modified them slightly to reduce the potential for multiple violations due to a single event.<br><br>e. R5: We do not agree that the VSL should be a single “Severe”. R5 contains 3 subrequirements. Presumably, a TSP may fail one or more of these subrequirements. A progressive (graded) VSL should be developed.<br>**Response:** The SDT has modified the VSLs for R5 to have a more progressive approach, but does not believe simply counting the sub-requirements is an effective way to measure compliance with this standard.<br><br>f. R6: We assess that R6.1 and R6.2 are parts of a single process requirement. However R6.3 and R6.4 are distinct requirements that need to be met as well. Presumably, a TSP may fail anyone or more of the 3 subrequirements (R6.1 and R6.2 as a unit). Again, a progressive (graded) approach would be more appropriate. We suggest the SDT to revise the VSL for this requirement.<br>**Response:** The sub-requirements under R6 describe the overall process by which TTC should be calculated, and is where the TTC process meets SOL/IROL requirements. If any or all of these sub-requirements are violated, the entity is not following the standard and the VSL should be Severe.<br><br>g. R7: the second “OR” under the Severe column should be “AND” since the first two conditions both mean that the TOP fails R7.1 completely, but it’s only a part of R7. It needs to also fail R7.2 completely |

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| | | to have a Severe failure. To cover for case where the TOP fails either R7.1 or R7.2 completely but not both, the conditions under High may be revised to remove the "but not been more than" parts and include the ?did not provide?? as an OR condition.<br>**Response:** The SDT disagrees. R7, as written, requires the Transmission Operator to deliver all its TTCs within a certain time frame. The SDT believes that not delivering a significant number of the values, or delivering those values grossly late, is a severe violation.<br><br>h. R8: We would assume the "M9" referenced in this set of VSL really meant "M10", or else these VSLs would be difficult to understand since R8 is on using the algorithm, not on the values whereas M9 is for R7 that stipulates the requirement for establishing TTC values. Please also see our comments on M10 under Q1.<br>**Response:** The reference to the measure has been corrected.<br><br>i. R9: Same comment as in VSLs for R8, except in this case the "M10" should be "M11". Please also see our comments on M11 under Q1.<br>**Response:** The reference to the measure has been corrected |
| **Response:** Please see in-line responses. | | |
| IRC Standards Review Committee | No | No. We suggest the following see IESO |
| **Response:** Please see IESO responses. | | |
| Hydro One Networks | No | Note R1 has 5 sub-requirements, not four. In the VSL's for R1 include the statement, "Any violation or violations of the sub-requirements of R1.5 shall be considered a single violation of R1.5. The Lower VSL contains older wording and should be updated to similar wording as the rest of the levels: "The TSP has an ATCID but it is missing x of the five required elements in R1.<br>**Response:** The SDT agrees and has modified the VSLs for R1.<br><br>The VSLs for R2 should be graded based on % to cater to different size systems.<br>**Response:** The SDT does not believe determining a percentage is as easy as is suggested by the commenter. Variations in determining what constitutes the facilities that enter into the denominator would make this a difficult item to measure, with significant discretion in determining the percentage. Because of this difficulty in measuring the value, the SDT believe it is appropriate to leave the numbers in the VSLs as fixed counts.<br><br>Also what is the logic behind using voltage 161 kV in the severe level?<br>**Response:** If an entity equivalences any non-radial lines with nominal voltage greater than 161kv, they |

| Organization/Group | Question 3: | Question 3 Comments: |
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| | | failed to meet requirement R2.1. R2.1 is a pass/fail requirement (not given a gradient on the violation severity levels) therefore it must be given a severe violation.<br><br>The VSLs for R3 should also be graded based on %.<br>**Response:** The SDT does not believe determining a percentage is as easy as is suggested by the commenter. Variations in determining what constitutes the facilities that enter into the denominator would make this a difficult item to measure, with significant discretion in determining the percentage. Because of this difficulty in measuring the value, the SDT believe it is appropriate to leave the numbers in the VSLs as fixed counts.<br><br>Correct VSLs for R8 and R9 with the correct reference to their Measures.<br>**Response:** The reference to the measure has been corrected. |
| Gainesville Regional Utilities | Yes | Good improvement. |
| **Response:** Thank you for your supportive comment. | | |
| APPA | Yes | Major improvement. We will want to refine in the future but good work here. |
| **Response:** Thank you for your supportive comment. | | |
| Kansas City Power & Light | Yes | |
| SERC ATCWG | Yes | |
| Public Service Commission of South Carolina | Yes | |
| Duke Energy Corporation | Yes | |
| Oncor Electric Delivery | Yes | |
| Bonneville Power | Yes | |
| MRO?? | Yes | |
| Texas-New Mexico Power Company | Yes | |
| Orlando Utilities | Yes | |
| EPSA | | no comment |

4. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-028.

**Summary Consideration:**

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

The NERC RTOSDT expressed concern that the standard does not refer to Planning and operating limits. The SDT directed the RTOSDT to the specific areas in the methodology standard where such references are made.

Several entities expressed concern regarding the responsibilities of the Transmission Operator. The SDT interprets the Functional Model as requiring the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. For those entities who believe the TSP to be the appropriate entity, we reiterate that options for delegation of this task exist.

| Organization/Group | Question 4 Comments: |
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| CenterPoint Energy | The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a single control area. |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| ERCOT ISO | I suggest modifying the Applicability section as follows:"4.1. Each Transmission Operator with ATC Path(s) that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.""4.2. Each Transmission Service Provider with ATC Path(s) that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths." |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard. | |

| Organization/Group | Question 4 Comments: |
|---|---|
| Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. *(Loc. Cit.)* | |
| NERC RTOSDT | The Real Time Operation Standards Drafting Team is concerned that the proposed MOD standards do not include any reference to the Planning and Operating Limits mandated by the current FAC, IRO and TOP standards. These standards already include transmission flow limits both in the longer term planning time frame as well as the shorter term operating time frame. The proposed MOD standards seem to be establishing procedures to calculate the commercial boundaries without a direct link to the required reliability boundaries.<br><br>MOD-001 R6 states that the TTC “use assumptions” no more limiting than those used in planning. The RTO SDT would ask shouldn’t TTC’s be required to be “no less limiting” than the SOLs / IROLs computed for the system?<br><br>Current NERC standards are not just asset limits, they are also system limits. The current standards require that limits be calculated that recognize both local and wide-area impacts. The RTO SDT believes that by at least linking (if not entirely eliminating) the MOD standards to the current SOLs / IROLs requirements, the Industry would be more correctly linking how the system MUST BE operated to any NAESB business practice. Indeed it would seem that current tariffs are based on the computations used in current planning and operating environments. By using the current SOL / IROL limits the procedural / prescriptive requirement in MOD-001 R9 et al would be unnecessary (i.e. they would revert back to the FAC and IRO requirements)<br><br>The questions for the ATC SDT:<br>• How do these MOD standards relate to the SOLs / IROLs?<br>• Why should these ATC/TTC limits be decoupled from the SOLs / IROLs?<br>• Shouldn’t the long-term SOL / IROL limits computed in Planning be the TTC for the system (or at least the basis for the TTC)?<br>• Shouldn’t the short-term SOL / IROL be the basis for the ATC for the system — MOD-008 computes margins.<br><br>By coordinating the MOD standards with the SOL / IROL standards, the only Business (not NERC) requirement may be to define the options on how the TSP could couple the various SOL / IROL values that it obtains from its RCs and TOPs. MOD-028By using SOLs / IROLs there would be no need to get into ATC / AFC “methodologies”. Indeed standards that include “alternatives” are not defining a single “standard approach”. But by using specific planning and operating limits the methodologies become irrelevant. The “limit” becomes explicit and well-defined. Any margins or variations about |

| Organization/Group | Question 4 Comments: |
|---|---|
| | those limits would then be obvious and transparent. What is most important is respecting the reliability-based limits and not how the commercial value is computed. If this idea of using SOLs / IROLs as the limit(s) or at least the basis for those commercial limits, then the TSP becomes a coordinator of which values to use for the commercial periods. The TSP would not be the computer of those limits. Thus MOD-028 could become a business practice for posting — rather then a standard for computations. |
| **Response:** With regard to the comments on setting Planning and Operating Limits, the MOD-028, MOD-029 and MOD-030 posted methodology standards include references to SOLs to address the concerns expressed by the RTO SDT. These references are as follows: MOD-028 R6.1; MOD-029 R3; MOD-030 R2.4. Regarding the need for these standards, the approval of the SAR related to these standards and the NOPR process for Order 890 has already identified that the industry believes these methodologies are appropriate areas for standards development. With regard to the comment "The RTO SDT would ask shouldn't TTC's be required to be "no less limiting" than the SOLs / IROLs computed for the system?" the SDT notes that MOD-028 does not contain "no more limiting" language. Instead, MOD-028 requires that SOLs be respected in R6.1. | |
| AEP | The Applicability of this Standard should be solely upon the TSP, the Transmission Operator should not be subject to this Standard. From the previous set of responses, it is the apparent belief of the SDT that the calculation of ATC is needed for reliability (response to AECI for example). We disagree. Considering that ATC is a mathematical amalgamation of forecasted system conditions (load, outages, generation dispatch, others? transactions, etc) compounded and adjusted by margins (TRM and CBM of own entity and other systems), using the calculated ATC to assess real or near real time transmission reliability would be ? at best ? unwise. Transmission Reliability can be assessed by monitoring specific and individual Facility loadings and/or other parameters, for example. The calculation of ATC and the value of resultant ATC is exactly for the purpose stated in the definition of ATC: "A measure of ? capability?. for further commercial activity? ? and note the definition does not infer ATC is a measure of reliability. Granted, ATC is calculated FROM reliability derived values and concepts (such as ratings, contingency analysis aspects, SOLs etc), BUT the resultant ATC values are not an assessment of transmission reliability ? and therefore not a function for the Transmission Operators, but rather the Transmission Service Provider.<br>**Response:** The Drafting Team does not find any clear rationale for selecting the Transmission Service Provider as the entity responsible for selecting the methodology. As discussed previously, the Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints.<br>For those entities who believe the TSP to be the appropriate entity, we reiterate that options for delegation of this task exist. Transmission operators can simply defer to the decisions made by their Transmission Service Provider; if a more formal agreement and transfer of responsibility is needed, the Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service provider agreeing to take on responsibility for this requirement through written contract.<br><br>In addition, the Purpose statement is unclear and perhaps nonsensical. Is the purpose ? to increase consistency and reliability in the development of documentation?.? or ? to support analysis and system operation?? What entities? ?short term use?? Suggestion: Purpose: To ensure consistency of calculation of those entities employing Area Interchange |

| Organization/Group | Question 4 Comments: |
|---|---|
| | Methodology pursuant to MOD-001 R1.<br>**Response:** As for the Purpose statement being nonsensical, AEP inaccurately quotes the language of the "Purpose" statement as being for "the development of documentation" (emphasis added); whereas the actual Purpose statement is to promote "the development and documentation of transfer capability calculations." (emphasis added). This statement clearly aligns with FERC's Order 693, P. 1015 wherein FERC states the purpose of the ATC suite is to promote "consistency and transparency for ATC calculations." As for the ambiguity of applicable entities in the Purpose statement, AEP is reminded that the Applicable entities are clearly stated in the Applicability section – not the Purpose section. As for short-term, FERC suggests that short-term is operational whereas long-term is planning in nature. Order 693, P. 1040. See also Order 890, P. 292 – 295. |
| **Response:** Please see in-line responses. | |
| PJM | PJM reiterates that while we will not choose the calculation methodologies used in MODs 28 and 29, these MODs will require modification to assure consistency with any revisions made to MOD 30. PJM is including specific comments for MOD 30 in Section VI of this document. PJM is not providing specific comments for MODs 28 and 29. |
| Oncor Electric Delivery | This standard should not apply to ERCOT for the reason expressed in question 1. |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| Hydro One Networks | We question the retirement of standards FAC-012 and FAC-013 as indicated in the implementation plan as those FAC standards pertain to different responsible entities than these MOD standards. |
| **Response:** The SDT believes that while these did apply to different functional entities, the tasks have been appropriately addressed within the new standards. Additionally, the SDT believes that since the various methodologies are all dependent on the calculation of TTC consistent with the methodology chosen, the requirements from the FAC-012 and FAC-013 standard must be included within the methodologies themselves. Otherwise, entities could calculate TTC using one methodology and ATC with another (but using the inconsistently determined TTC). | |
| MRO | 1. The MRO continues to have issues with the overall approach on this standard in combination with the MOD-030. As previously indicated in prior comment periods, the MRO has Transmission Service Providers that manage the levels of transmission service to a reliable level with flowgates and then establishes border control area-to-control area flows to contract path levels so that contractual rights are not exceeded. The MRO reads the MOD-028 standard to require the application of the MOD-028 methodology for its control area-to-control area path postings while MOD-030 standard is used for the flowgates postings. The MRO understands from a discussion with a member of the SDT that in actuality the |

| Organization/Group | Question 4 Comments: |
|---|---|
| | intent is that the MOD-030 would be used for flowgate calculations and that these quantities could be converted into the ATC path quantities for the control area to control area paths from border companies to outside the Transmission Service Providers area. This application of the flow gate methodology to possibly generate all postings for a Transmission Service Provider including drive out is not clear from the standards and should be clarified in MOD-030 and possibly MOD-028.<br>**Response:** The SDT does not see a need to modify MOD-028 in response to this comment; any clarification would be done in MOD-030.<br><br>2. The MRO commends the SDT in making significant changes to this standard and reissuing it for comment. The MRO believes the eventual standard that is approved will serve the industry and customers better as a result.<br>**Response:** Thank you for your support<br><br>3. The MRO believes that the first time you use an abbreviation or acronym, you must spell out the full term followed by the abbreviation or acronym in brackets. Subsequent use of the term is then made by its abbreviation or acronym. ex: "Each Transmission Operator shall select one Available Transfer Capability (ATC) methodology2 for calculating ATC (Area Interchange methodology, Rated System Path methodology) or Available Flowgate Capacity (AFC) (Flowgate methodology) for each ATC Path per time period identified in R2 for those Facilities within its Transmission Operator Area."<br>**Response:** The SDT has modified MOD-028 where required. |
| **Response:** Please see in-line responses. | |
| American Public Power Association | These comments apply equally to MOD-1, MOD-28. MOD-29 and MOD-30Excellent work by the SDT. |
| **Response:** Thank you for your supportive comment. | |
| Texas-New Mexico Power Company | This standard should not apply to ERCOT for the reason stated in Question 1. |
| **Response:** This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology. To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |

<table>
<tr><th>Organization/Group</th><th>Question 4 Comments:</th></tr>
<tr><td>Brazos Electric Power Cooperative, Inc.</td><td>Brazos Electric believes that the concept of an Area Interchange Methodology is not applicable to a single-control area operation like ERCOT.  To address this issue, the Applicability section could be modified to state that only TOPs or TSPs that conduct area to area operations and hence have responsibility for ATC Path(s) must have an Area Interchange Methodology.</td></tr>
<tr><td colspan="2">Response: This standard is intended to apply to all entities that have chosen to implement the Area Interchange methodology.  To the extent ERCOT does not choose to implement this methodology, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard.  The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system.    The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.”  <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u>  The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT.  (Loc. Cit.)</td></tr>
<tr><td>Orlando Utilities Commission</td><td>All the requirements and measures look great.  One question on R8 and R9.  In R8 and R9, it is obviously required that ETC is determined using only the inputs specified, however is it necessary to determine each of the individual inputs and then sum them to get ETC?   For example the method for determining ETC might take into account only those items and their effect on the path, but may not break them out into their individual values (NITS, GF, PTP, OS) due to the nature of the method.</td></tr>
<tr><td colspan="2">Response:  The equations in R8 and R9 describe the components that must be considered in ETC, but do not dictate the process by which the value is calculated.</td></tr>
<tr><td>Bonneville Power</td><td>none</td></tr>
<tr><td>Gainesville Regional Utilities</td><td>None at this time.</td></tr>
<tr><td>Ontario IESO</td><td>None</td></tr>
<tr><td>EPSA</td><td>no comment</td></tr>
</table>

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
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5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC Conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Transmission Reliability Margin Implementation Document (TRMID):** A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**

2. **Number:** **MOD-008-1**

3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.

4. **Applicability:**

   **4.1.** Transmission Operators that maintain TRM.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value:

- Aggregate Load forecast.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve sharing requirements.
- Inertial response and frequency bias.

**R1.2.** The description of the method used to allocate TRM across ATC Paths or Flowgates.

**R1.3.** The identification of the TRM calculation used for the following time periods:

**R1.3.1.** Same day and real-time.

**R1.3.2.** Day-ahead and pre-schedule.

**R1.3.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

**R2.** Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.** Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

**R4.** Each Transmission Operator using TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.** The Transmission Operator using TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

## C. Measures

**M1.** Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, and CBMID , or other evidence, (such as written documentation, study reports, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide evidence (such as copies of emails or postal receipts that show the recipient, date and contents) that the requested documentation (such as work papers and load flow cases) was made available within the specified timeframe to the requestor. (R3)

**M4.** Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

**M5.** Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.

The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.

The Transmission Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago. | The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.<br>**OR**<br>The Transmission Operator's TRMID does not address one of the subrequirements (R1.1, R1.2, R1.3). Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3. | The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.<br>**OR**<br>The Transmission Operator's TRMID does not address two of the subrequirements (R1.1, R1.2, R1.3). Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3. | The Transmission Operator has a TRMID that does not incorporate changes that have been made one year ago or more.<br>**OR**<br>The Transmission Operator does not have a TRMID;<br>**OR**<br>The Transmission Operator's TRMID does not address three of the subrequirements (R1.1, R1.2, R1.3). Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3. |
| R2. | N/A | N/A | N/A | The Transmission Operator included elements of uncertainty not defined in R1 in their establishment of TRM.<br>**OR**<br>The Transmission Operator included components of CBM in TRM. |
| R3. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days. | The Transmission Operator did not make the TRMID available for 90 days or more. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R4 | The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (which ever is greater) were incorrect or missing. | The Transmission Operator did not establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago<br>**OR**<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). | The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago.<br>**OR**<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values. | The Transmission Operator did not establish TRM<br>**OR**<br>The last determination of TRM was more than 18 months ago.<br>**OR**<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing. |
| R5 | The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 days.<br>**OR**<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (which ever is greater) were incorrect or missing. | The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 days.<br>**OR**<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or incorrect. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). | The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 days.<br>**OR**<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values. | The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change.<br>**OR**<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing. |

## E. Regional Variances

None.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | April 1, 2005 | Effective Date | New |
| | | | |
| | | | |
| | | | |

## Standard Development Roadmap

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## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Transmission Reliability Margin Implementation Document (TRMID):** A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**

2. **Number:** **MOD-008-1**

3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.

4. **Applicability:**

   **4.1.** Transmission Operators that maintain TRM.

   ~~4.2.Transmission Service Provider.~~

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in ~~calculating~~ establishing TRM, and a description of how that component is used to ~~calculate~~ establish a TRM value:

- Aggregate Load forecast ~~uncertainty (not included in determining generation reliability requirements for CBM)~~.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).
- Reserve sharing requirements.
- Inertial response and frequency bias.

~~R1.2.A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in the Transmission planning process for the time period studied .~~

**~~R1.3.~~R1.2.** The description of the method used to allocate TRM across ATC Paths or Flowgates.

**~~R1.4.~~R1.3.** The identification of the TRM calculation used for the following time periods:

**~~R1.4.1.~~R1.3.1.** Same day and real-time.

**~~R1.4.2.~~R1.3.2.** Day-ahead and pre-schedule.

**~~R1.4.3.~~R1.3.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

~~**R1.5.**If TRM is not used, a statement of that practice.~~

**R2.** Each Transmission Operator shall only use the components of uncertainty from R1.1 to ~~calculate~~ establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. ***[****Violation Risk Factor: Lower**]*** ***[****Time Horizon: Operations Planning**]***

**R3.** Each Transmission Operator shall make available its TRMID, and if requested, ~~any~~ underlying documentation~~, work papers and load flow base cases~~ (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. ***[****Violation Risk Factor: Lower**]*** ***[****Time Horizon: Operations Planning**]***

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

**R4.** Each Transmission Operator using TRM shall ~~recalculate~~ establish TRM values in accordance with the TRMID at least once every 13 months. ~~–~~*[Violation Risk Factor: Lower~~Medium~~] [Time Horizon: Operations Planning]*

**R5.** The Transmission Operator using TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after ~~they~~ a TRM value is initially ~~change~~established or subsequently changed. ***[****Violation Risk Factor: Lower~~Medium~~**]*** ***[****Time Horizon: Operations Planning**]***

## C. Measures

**M1.** Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, and CBMID , or other evidence, (such as written documentation, study reports, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide ~~request for its TRMID or associated documentation, and~~ evidence (such as copies of emails or postal receipts that show the recipient, date and contents)~~ as evidence~~ that the requested documentation (such as work papers and load flow cases) was ~~provided~~ made available within the specified timeframe to the ~~entities described in R3~~requestor. (R3)

**M4.** Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it ~~recalculated~~ established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

**M5.** Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.

The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.

The Transmission ~~Service Provider~~Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations

- Self-Reporting
- Complaints

### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| **R1.** | **The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago.** | **The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.**<br>**OR**<br>**The Transmission Operator's TRMID does not address one of the ~~sub requirement~~**subrequirements **(R1.1, R1.2, R1.3). Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3.** | **The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.**<br>**OR**<br>**The Transmission Operator's TRMID does not address two ~~or three~~ of the ~~sub requirement~~**subrequirements **(R1.1, R1.2, R1.3). Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3.** | **The Transmission Operator has a TRMID that does not incorporate changes that have been made ~~more than~~ one year ago or more.**<br>**OR**<br>**The Transmission Operator does not have a TRMID;**<br>**OR**<br>**The Transmission Operator's TRMID does not address ~~4 or more~~three of the ~~sub requirement~~**subrequirements **(R1.1, R1.2, R1.3). Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3.** |
| **R2.** | **N/A** | **N/A** | **N/A** | **The Transmission Operator included elements of uncertainty not defined in R1 in their ~~calculation~~ establishment of TRM.**<br>**OR**<br>**The Transmission Operator included components of CBM in TRM.** |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Transmission Operator ~~provided~~ made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days. | The Transmission Operator ~~provided~~ made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days. | The Transmission Operator ~~provided~~ made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days. | The Transmission Operator did not ~~provide~~ make the TRMID available for 90 days or more. |
| R4<br><br>R5 | The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (which ever is greater) were incorrect or missing. ~~N/A~~<br><br>The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 | The Transmission Operator did not ~~determine~~ establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago<br><br>OR<br><br>The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). ~~.~~<br><br>The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 | The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago.<br><br>~~The Transmission Operator determined TRM 15 months ago or more, but not more than 18 months ago.~~<br><br>OR<br><br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.<br><br>The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 | The Transmission Operator did not ~~determine~~ establish TRM<br><br>OR<br><br>The last determination of TRM was more than 18 months ago ~~or more~~.<br><br>OR<br><br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing.<br><br>The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | **days.** ~~,~~<br>**OR**<br>**The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (which ever is greater) were incorrect or missing.** | **days.**<br>**OR**<br>**The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or incorrect. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater).** | **days.**<br>**OR**<br>**The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values.** | **OR**<br>**The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing.** |

## E. Regional Variances

None.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | April 1, 2005 | Effective Date | New |
| | | | |
| | | | |
| | | | |

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# Implementation Plan for Standard MOD-008-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-008-1 — Transmission Reliability Margin which describes the reliability aspects of determining and maintaining a Transmission Reliability Margin and what components of uncertainty may be considered when making that determination.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes MOD-008-0. MOD-009-0 — Procedure for Verifying Transmission Reliability Margin Values, has been incorporated into this standard, made irrelevant by this standard, or is being addressed by the North American Energy Standards Board, and should be retired when MOD-008-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-008-1 | ■ | | | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the reliability standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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# Implementation Plan for Standard MOD-008-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-008-1 — Transmission Reliability Margin~~,~~ which describes the reliability aspects of determining and maintaining a Transmission Reliability Margin and what components of uncertainty may be considered when making that determination.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## ~~Modified~~ Retired Standards

This standard supersedes MOD-008-0. MOD-009-0 – Procedure for Verifying Transmission Reliability Margin Values, has been incorporated into this standard, made irrelevant by this standard, or is being addressed by the North American Energy Standards Board, and should be retired when MOD-008-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-008-1 | ■ | | ~~■~~ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the reliability standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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Princeton, New Jersey 08540-5721
609.452.8060 | www.nerc.com

Please **DO NOT** use this form to submit comments on the current draft of MOD-008. Comments must be submitted by **May 15, 2008.**

If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-452-8060.

**Background Information MOD-008 — Transmission Reliability Margin** (A standard that describes the calculation and use of TRM.)

An initial ballot of MOD-008-1 — Transmission Reliability Margin was conducted March 3-12, 2008 and there were several suggestions for modifying the standard that were submitted with ballots. The drafting team withdrew the standard from the ballot process, and made several changes to the standard based on stakeholder comments, including the following:

1. The Drafting Team changed language throughout the standard to specify that TRM be "established" instead of "calculated".
2. The drafting team removed the requirement that the assumptions used in Transmission Reliability Margin studies be consistent with those used in "associated" operations or planning studies. Studies used for TRM are based on non-standard scenarios, and would be inappropriate to make consistent with "normal" studies.
3. Several VRFs were changed from "Medium" to "Lower" in response to industry comments. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
4. A more graded approach was applied to the VSLs where appropriate.

**Please review the revised version of MOD-008 and then answer the following questions. You do not have to answer all questions. Enter All Comments in Simple Text Format.**

1. **Some entities have indicated they believe the Transmission Operator should not be an applicable entity in the TRM standard (MOD-008). The Drafting Team believes that the Transmission Operator is the appropriate entity since the Transmission Operator is ultimately responsible for operating a reliable system while using all Transmission Service Providers' calculated available capability. The drafting team also believes that the Transmission Operator can, via mutual agreement, delegate these tasks to other entities (such as Transmission Service Providers, ISOs, or RTOs). Do you believe the Transmission Operator is the correct responsible entity for the tasks it has been assigned in MOD-008?**

   ☐ Yes

   ☐ No

   ☐ No preference

   **If "No," please identify requirements where the Transmission Operator is incorrect and specify who the correct entity should be.** Comments:

2. **The drafting team modified some requirements and associated measures to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct.**

   Incorrect Requirement(s) or Measure(s):

3. **The drafting team has modified the Violation Risk Factors for MOD-008 to reflect industry concerns that they did not reflect NERC's VRF definitions. NERC's VRF definitions are listed below:**

   **High Risk Requirement**:
   (a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or
   (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

   **Medium Risk Requirement**:
   (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

**Lower Risk Requirement**: is administrative in nature and
(a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or
(b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

**Are the current VRFs established correctly?**

☐ Yes
☐ No

**If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.**
Comments:

4. **The drafting team has modified the Violation Severity Levels for MOD-008 to reflect industry concerns that they were too "pass/fail" oriented. Are the current VSLs established correctly?**

   ☐ Yes
   ☐ No

   **If "No," please identify specific VSLs and suggest changes to the language.**
   Comments:

5. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on MOD-008.**

   Comments:

| | Individual or group. | Name | Organization | Group Name | Lead Contact | Question 1 | Question 1 Comments | Question 2 | Question 3 | Question 3 Comments | Question 4 | Question 4 Comments | Question 5 Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Individual | Paul Rocha | CenterPoint Energy | | | | | | | | | | The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a single control area. |
| | Group | | | SERC ATCWG | Doug Bailey | No preference | | | Yes | | Yes | | |
| | Individual | Jack Cashin/Barry Green | EPSA | | | No preference | | We believe that the former requirement R1.2 which established the consistency between planning assumptions and those used in calculation TRM was appropriate and do not agree with its deletion. In R3, the previous draft of the standard required sharing of "underlying documentation, work papers and load flow base cases". In the current draft, the latter two of the listed items have been deleted. It is acceptable to us if this is done merely because they are deemed to be redundant as they are included within the meaning of "underlying documentation". If this was not the intent of the drafters, we would disagree with this change as those are items that would be required in order to reproduce the studies that have led to the posted ATC values. | | no comment | | no comment | This comment relates also to the NAESB recommendation that no additional business practices related to TRM will be developed. Our comments are based also on Order 890 Paragraph 207 which states in part: "The purpose of increasing the consistency and transparency of ATC calculations is to reduce the potential for undue discrimination in the provision of transmission service, specifically by reducing the opportunity for transmission providers to exercise excessive discretion. We find that the amount of discretion in the existing ATC calculation methodologies gives transmission providers the ability and opportunity to unduly discriminate against third parties. In order to minimize this discretion, the Final Rule requires that all ATC components (i.e., TTC, ETC, CBM, and TRM) and certain data inputs, data exchange, and assumptions be consistent and that the number of industry-wide ATC calculation formulas be few in number, transparent and produce equivalent results." EPSA does not believe that the mandate given by FERC to NERC and to NAESB has been carried out. EPSA accepts that in calculating ATC, Transmission operators need a margin, which is deducted from the TTC or AFC as appropriate, to allow for uncertainties in forecast conditions and thus to insure that Transmission Service is not oversold. As it represents an allowance for uncertainties, it is recognized that TRM is based on assumptions about future conditions and is in general, determined probabilistically. However, based on the proposed actions of the two standards development organizations, in order to meet FERC's Order to "increas[e] the consistency and transparency of ATC calculations" and to "reduc[e] the opportunity for transmission providers to exercise excessive discretion" the industry has provided standards that: • Require Transmission Operators to only identify various elements if they are used in establishing TRM. At no point in the standard however, is any direction provided on how the Transmission Operators determine whether or not to use the various components or, if used, how values are to be established. • Make no provision for monitoring or reporting on utilization of TRM • Make no provision for verifying from season to season or year to year whether the values utilized in establishing TRM were or remain appropriate. These standards therefore impose only a minimal requirement for transparency and no requirement for consistency in establishing TRM and no requirement to monitor its usage to verify that assumed values are appropriate. The current NERC and NAESB standards on TRM are reminiscent of the previous NERC standard on ATC which was developed in response to Order 888. It required only that Transmission Operators document their methodology for calculating ATC, much like other fill-in-the-blank standards. Clearly in approving Order 890 and more particularly in Order 693 where they declined to approve other industry fill-in-the-blank standards, FERC has determined that such a standard is insufficient. Yet, with respect to TRM, the industry, through NERC and NAESB, seems prepared to submit standards to FERC that demonstrate that very little progress has been made. |
| | | | | | | | | The Team suggests moving the final phrase of the proposed R3 Requirement to the beginning of the sentence to add clarity. (This is a non-substantive change.) The new R would read: No | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Group | | | WECC Market Interface Committee / Sub Committ / ATC Task Force | W. Shannon Black | Yes | | more than 30 calendar days after receiving a request, each Transmission Operator shall make available its TRMID, and if requested, its underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request for that data: | Yes | | Yes | | | |
| | Individual | Jim Usedinger | Kansas City Power & Light | | | No | The Transmission Service Provider should also be listed as an appropriate entity along with the TOP in all requirements, so that either entity could perform this function. | Add "or Transmission Service Provider" after Transmission Operator in all requirements. | Yes | | Yes | | | |
| | Group | | | WECC Market Interface Committee ATC Task Force | W. Shannon Black | Yes | | The Team suggests moving the final phrase of the proposed R3 Requirement to the beginning of the sentence to add clarity. (This is a non-substantive change.) The new R would read: No more than 30 calendar days after receiving a request, each Transmission Operator shall make available its TRMID, and if requested, its underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request for that data: | Yes | | Yes | | | |
| | | | | | | | | Requirement 1: I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) and with TRM shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following | | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Individual | H. Steven Myers | ERCOT ISO | | | No preference | | information:" Requirement 2: I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) and with TRM shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM." Requirement 3: I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) and with TRM shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request." | | | | | |
| | | | | | | | | In MOD-008-1 the following requirement was removed: R1.2.A A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in the Transmission planning process for the time period studied". The NERC ATCWG reached conclusion on the following rule as they were developing the “Transmission Capability Margins and Their Use in ATC Determination” white paper which discusses the reliability margins of TRM and CBM: A Transmission | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Provider's ATC/AFC calculations, and associated margins, must be consistent with the Transmission Owners' and Public Power Entities documented Planning Criteria This rule was incorporated into the "Transmission Capability Margins and Their Use in ATC Determination" white paper dated June 17, 1999 as demonstrated in the following exert: Ø "The methodology used to derive TRM and its components must be documented and consistent with published planning criteria, and must not account for uncertainties already accounted for elsewhere in the ATC determination. A TRM is considered consistent with published planning criteria if the same components that comprise it are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process" AFC/ATC calculations must be consistent with each Transmission Owner's planning criteria in order to maintain reliability. AFC/ATC calculations must | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Individual | Eric Mortenson | Exelon | | | Yes | | not be subject to evaluation scenarios that exceed or are 'beyond' the applicable planning criteria. For example, if the most extreme event a Transmission Owner plans for were single contingencies, it would be inconsistent with the applicable planning criteria to evaluate a transmission service request to meet a double contingency test. In this instance, evaluating a transmission service request using double contingency analysis would be in conflict with the planning criteria and would not be compatible with the reliability requirements used to serve native connected load. In an ATC calculation the following components determine the loading on a flowgate for the period of time under evaluation: 1. Base Case Flows (which recognizes the forecasted load connected to the transmission network and planned system topology) 2. Impacts of existing transmission service reservations -- both positive and negative (i.e. counterflow) 3. TRM (consistent with applicable Planning Criteria) 4. CBM (consistent with applicable Planning Criteria) When these four components are applied to a flowgate the result is a calculated AFC. If the resultant AFC is negative, the result indicates that the flowgate is projected to be overloaded because of the preexisting commitments (i.e. | | | | | |

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| | | | | | | | the four components listed above). In some cases negative AFC values exist for future years preventing transmission customers from obtaining transmission reservations for these future time periods. The inconsistency between Transmission Provider's AFC/ATC calculations and the Transmission Owner's Planning criteria becomes evident when the Transmission Owner internal planning processes does not result in identification of system deficiencies requiring system expansion – even on Flowgate determined by the Transmission Provider to have negative AFC values far into the future. The likely cause of this discrepancy is that the TO is not applying the same scenario, including the same transmission uses (i.e. confirmed reservations), or consistent margins (TRM/CBM) in its internal planning process. | | | | | |
| Individual | Maria Neufeld | Manitoba Hydro | | | No preference | | | Yes | | Yes | | |
| Group | | | NERC RTOSDT | Jim Case, Chair | | | | | | | | The Real Time Operation Standards Drafting Team is concerned that the proposed MOD standards do not include any reference to the Planning and Operating Limits mandated by the current FAC, IRO and TOP standards. These standards already include transmission flow limits both in the longer term planning time frame as well as the shorter term operating time frame. The proposed MOD standards seem to be establishing procedures to calculate the commercial boundaries without a direct link to the required reliability boundaries. ============================================================ MOD-001 R6 states that the TTC "use assumptions" no more limiting than those used in planning. The RTO SDT would ask shouldn't TTC's be required to be "no less limiting" than the SOLs / IROLs computed for the system? Current NERC standards are not just asset limits, they are also system limits. The current standards require that limits be calculated that recognize both local and wide-area impacts. The RTO SDT believes that by at least linking (if not entirely eliminating) the MOD standards to the current SOLs / IROLs requirements, the Industry would be more correctly linking how the system MUST BE operated to any NAESB business practice. Indeed it would seem that current tariffs are based on the computations used in current planning and operating environments. By using the current SOL / IROL limits the procedural / prescriptive requirement in MOD-001 R9 et al would be unnecessary (i.e. they would revert back to the FAC and IRO requirements) The questions for the ATC SDT: • How do these MOD standards relate to the SOLs / IROLs • Why should these ATC/TTC limits be decoupled from the SOLs / IROLs • Shouldn't the long-term SOL / IROL limits computed in Planning be the TTC for the system (or at least the basis for the TTC) • Shouldn't the short-term SOL / IROL be the basis for the ATC for the system? MOD-008 computes margins. By coordinating the MOD standards with the SOL / IROL standards, the only Business (not NERC) requirement may be to define the options on how the TSP could couple the various SOL / IROL values that it obtains from its RCs and TOPs. MOD-028 By using SOLs / IROLs there would be no need to get into ATC / AFC "methodologies". Indeed standards that include "alternatives" are not defining a single "standard approach". But by using specific planning and operating limits the methodologies become irrelevant. The "limit" becomes explicit and well-defined. Any margins or variations about those limits would then be obvious and transparent. |

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| | | | | | | | | | | | | | What is most important is respecting the reliability-based limits and not how the commercial value is computed. If this idea of using SOLs / IROLs as the limit(s) or at least the basis for those commercial limits, then the TSP becomes a coordinator of which values to use for the commercial periods. The TSP would not be the computer of those limits. Thus MOD-028 could become a business practice for posting – rather then a standard for computations. |
| | Group | | | NPCC Regional Standards Committee | Guy V. Zito | Yes | | None | | | Yes | | The language in the Proposed Effective Date should be modified to be consistent with the other standards |
| | Group | | | FirstEnergy | Doug Hohlbaugh | No | Within many RTO areas it is the TSP who maintains the TRM Methodology and assures its appropriate implementation while calculating ATC or AFC. This is the case in a large portion of the continent and a standard should not be written in a way that would knowingly require an assignment delegation for a large number of potential responsible entities. Assigning the applicability in this standard to the TSP would work for non-market areas of the continent since in those areas the TOP most likely serves as its own TSP. | R2 – This requirement states "Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM." We recommend replacing "only use" with "include" since "only use" presumes that the list of uncertainties stated in the standard are all inclusive of all factors that a TOP/TSP may want to address in TRM. The requirement explicitly states that CBM should not be included in TRM, so making this change should not create an opportunity for double dipping on CBM. | Yes | FE supports the SDT's adjustment of VRFs such that no VRF within the ATC standards exceeds a "Lower" rating. We concur with the team's reasoning and rationale provided in response to ballot comments in making this change. | No | The Severe VSL stated for requirement R2 does not seem appropriate if a TOP/TSP included elements of uncertainty that were outside of those items explicitly stated in R1 so long as all of the items in R1 are covered AND that CBM is not included in its TRM. See proposed change above for R2. | FirstEnergy appreciates the Standard Drafting Team's decision to move to a formal comment period based on the prior initial ballot feedback. We commend the team for moving quickly to respond to the ballot comments and providing the industry a revised set of standards to review and comment. Regarding the revision to the Effective Date, while FirstEnergy agrees that there is a need to ensure that the standard is implemented consistently across the entire continent we are concerned with the Effective Date being subject to approval of ALL regulatory authorities. We believe an appropriate Implementation Plan should reflect a period of time beyond the NERC Board of Trustee approval date that would reflect when the requirements are considered mandatory and enforceable. The timeline should allow sufficient time for regulatory authority reviews, with the intent of sanctions also being enforced in conjunction with the conclusion of the implementation period. However, a delay from a given regulatory agency should not impact when the requirements are considered mandatory and enforceable for the bulk electric system. |
| | Individual | Thad Ness | AEP | | | No | The Transmission Service Provider is the applicable entity. | | | | | | |
| | Group | | | Public Service Commission of South Carolina | Phil Riley | No preference | | | Yes | | Yes | | |
| | Individual | Patrick | PJM | | | Yes | | Although the SDT had the appropriate Team to establish a default percentage for TRM, the FERC deadline did not allow enough time to complete this portion of the requirement. Since TRM is a reliability margin, PJM encourages the Team to provide what ever input it currently has in a 'parking lot' for a possible future Team to | Yes | PJM supports NERC's position to revise all Violation Risk Factors to have an assigned risk factor of "Lower." A Lower Risk Factor requirement is administrative in nature and is a requirement | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the | |

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| | | Brown | | | | | | undertake the development activity. There should be a default percentage to be used without requiring specific documentation, work papers and load flow cases if a straight percentage such as 5% is used. Additional information would be required only if a greater percentage is used. | | that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. | | possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations –this language to be added to the standard. | |
| | Individual | Greg Rowland | Duke Energy Corporation | | | Yes | | | Yes | | Yes | | Implementation Plan – Since R2 and M2 link the TRM calculation methodology with the CBM methodology in MOD-004, implementation dates for these standards should be aligned. Since R2 and M2 link the TRM calculation methodology with the CBM methodology in MOD-004, the Standards Drafting Team must avoid creating a duplicate requirement the CBM standard, which could subject entities to multiple penalties for the same violation. |
| | Group | | | Bonneville Power | Denise Koehn | Yes | | BPA does not believe any are incorrect. | Yes | | Yes | | BPA respectfully submits the following observations and suggestions: a. The sixth component of uncertainty listed in R1.1 should be expanded as follows: - Variations in generation dispatch (including forced or unplanned outages, maintenance outages, and location of future generation). b. To comply with FERC Order 890 transparency requirements, R1.5 should not be removed (e.g. "If TRM is not used, a statement of that practice.") – BPA believes a Transmission Operator should be required to provide a robust justification as to why it is not using TRM in it's ATC or AFC calculations. c. A new R6 should be added that clearly states the timeframe in which TRM is to be used (i.e. within the hour). d. The Time Horizons listed for all requirements should include the "Long-term Planning" Horizon, as TRM is to be calculated beyond the seasonal window. e. Balancing Authorities may be appropriately identified as Applicable Entities in this MOD and request that the Standards Drafting Team provide an explanation as to why they are not listed. |
| | Individual | Greg Ward / Darryl Curtis | Oncor Electric Delivery | | | No preference | | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path (s). | Yes | | Yes | | This standard should not apply to ERCOT for the reason expressed in question 2. |
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| | Individual | Richard Kafka | Pepco Holdings, Inc | | | Yes | | comments of PJM and will not submit duplicate comments | | | | | |
| | Individual | Earl Fair | Gainesville Regional Utilities | | | No | I would suggest the TSP and let that entity negotiate, via mutual agreement, to delegate these task. | R2: Why limit what items can be considered in developing TRM? What reliability purpose could it possibly serve? R1,3,4 & 5 are OK as presented. | Yes | | Yes | | None at this time. |
| | Group | | | ISO RTO Council/Standards Review Committee (SRC) | Charles Yeung | Yes | | | Yes | The MOD standards assess the correct amount of reliability risk in areas that do not affect reliability. The IRC supports the position that no requirement from this set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but the IRC has a concern regarding the possibility of multiple violations resulting from a single event. The IRC requests that the potential for double counting of violations for a single event be eliminated. | Although the SDT had the appropriate Team to establish a default percentage for TRM, the FERC deadline did not allow enough time to complete this portion of the requirement. Since TRM is a reliability margin, the IRC encourages the Team to provide what ever input it currently has in a 'parking lot' for a possible future Team to undertake the development activity. There should be a default percentage to be used without requiring specific documentation, work papers and load flow cases if a straight percentage such as 5% is used. Additional information would be required only if a greater percentage is used. |

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| | Group | | | MRO NERC Standards Review Subcommittee | Tom Mielnik | Yes | | 1. The MRO believes that M1 should be revised to delete the words "all" from the phrase "all specified information…". This use of "all" seem to be unnecessary and may result in over-the-top auditing. 2. The MRO commends the SDT on deleting R1.2.A and R1.5. The MRO believes that these former requirements were unnecessary and not reliability related and that the changes are significant improvements to the standard. 3. The MRO is asking for clarification in R1.1 on "Reserve sharing requirements". The MRO is assuming that this is not non-operating reserves such as planning reserves. 4. R1.1, bullet 7 reads: Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window). The "59-minute window" conflicts with BAL-002. Under BAL-002, operating reserves can be supplied for up to 105 minutes (R4.2 15 minutes for the disturbance plus R6.2 90 minutes). We suggest the following wording instead: "(Operating Reserve actions not exceeding the operating reserve sharing deployment period)". | Yes | The MRO commends the SDT on revising the VRFs to Lower. We believe the revised VRFs are in-line with the NERC definitions of the VRF levels. | Yes | | 1. The MRO commends the SDT in making significant changes to this standard and reissuing it for comment. The MRO believes the eventual standard that is approved will serve the industry and customers better as a result. 2. The MRO believes that the first time you use an abbreviation or acronym, you must spell out the full term followed by the abbreviation or acronym in brackets. Subsequent use of the term is then made by its abbreviation or acronym. |
| | | | | | | | | | | The VRF for R4 should be a Medium. R4 stipulates that the TOP establish a TRM. Given that TRM is that portion of the ATC reserved to cover for | | | |

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| | Individual | Ron Falsetti | Ontario IESO | | | Yes | | None | No | uncertainties that can affect transmission reliability, failure to establish this value could result in the TOP facing unreliable operations due to the TSP offering and committing this value as a transmission service to transmission users. The end result could have a direct impact on the control and reliability of the BES. | Yes | | The language in the Proposed Effective Date should be modified to be consistent with the other standards |
| | Individual | Alessia Dawes | Hydro One Networks | | | Yes | | none | Yes | | Yes | | Language in the Proposed Effective Date should be modified to be consistent with the other standards, e.g. MOD-001-1 |
| | Group | | | Entergy Services Inc. | Narinder K. Saini | Yes | | R2- Entergy recommends deleting the phrase "and shall not include any of the components of Capacity Benefit Margin (CBM). | Yes | | Yes | | |
| | Individual | John Harmon | The Midwest ISO | | | Yes | | R1.1 – Please clarify the uncertainty components below: o Allowances for simultaneous path interactions (how is it different from loop flow above?) o Short-term System Operator response (Does this exclude reserve sharing requirements?). R2 – This requirement as it is written doesn't allow the Transmission Operators to include any other uncertainties other than from R1.1. If R1.1 is not trying to list the complete set of uncertainties, we recommend to revise R2 to "Each Transmission Operator shall not include any of the components of Capacity Benefit Margin (CBM). ..." | Yes | | Yes | | |
| | Group | | | Southwest Power Pool | Kevin Bates | Yes | | | Yes | | | | |
| | | | | | | | | Modification Requirement 1: Each TOP shall prepare and keep current a Transmission Reliability Margin | | | | | |

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| | Individual | Jason Shaver | American Transmission Company | | | Yes | We agree that the Transmission Operator is the correct entity but are concerned with the inserted exlcusion. Why did the SDT insert the exclusion in this draft of the Standard? (No previous drafts contained this exclusion.) How would a TOP go about notifing NERC that MOD-008 is not applicabile to them? How would NERC or the Regions know if something changed and the TOP is now performing TRM? When would this standard apply to a TOP that does not currenlty perform a TRM? An alternate approach is to have TOPs that do not perform TRMs, cerify yearly that they do not peform TRMs and therefore satisfy MOD-008-1. | Implementation Document (TRMID) that includes the following information: The phrase "as a minimum" is not needed because the TOP has to include all sub-requirement in order to meet requirement 1. Any information above that which is listed is outside of NERC's audit. Modifications to Requirement 4: Each TOP shall establish TRM values in accordance with the TRMID at least once every 13 months. Modification to Requirement 5: The TOP shall provide the TRM values to its TSP (s) and TP(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. The phrase "using TRM" conflicts with Requirements 1 - 3. In addition we believe the deletion aligns with our comment on the applicability section. M1 should be revised to delete the words "all" from the phrase "all specified information..." to avoid being overly inclusive. | Yes | | Yes | | The first time that each abbreviation or acronym is introduced, the full terminology should be stated followed by the abbreviation or acronym in brackets (i.e. ATC). The Proposed Effective Date for MOD-008-1 is different then that written for MOD-001-1. Why the difference in the Effective Date? We do not believe that the SDT has to provide a definition of TRMID. Requirement 1 outlines the specifics of TRMID and we find the definition unnecessary. The SDT should explain why this definition is necessary and what if anything is it including that the requirement does not already contain. |
| | | | | | | | We feel that the applicability should apply to the TSP, recognizing that the TSP will require input from the TOP. To further explain, the ATC/AFC methodology is primarily a mechanism for the TSP to sell/provide transmission service in a manner that ensures the transmission system is secure. A TOP however will utilize SOLs and IROLs in | R1.1, bullet 7 reads: Short-term System Operator response (Operating Reserve actions not exceeding a | | | | | |

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| | Individual | Alice Druffel | Xcel Energy | | | No | the operations of the transmission system, and do not necessarily have to be the same as the ATC/AFC components. As an example, in the selling of service, TRM will not be sold so the limit =TTC-TRM. However the TOP may operate into the TRM during real-time operations and not hold this margin, but honor the true system limit. As another example, there are interdependent flowgates where the ATC components will be based on the most conservative combination, but the system will be operated to minimize restrictions. This may result in a sliding operating limit for the TOP based on actual conditions, while a TSP has to use the most conservative limits for ATC/AFC. | 59-minute window). The "59-minute window" seems arbitrary and potentially conflicting. We suggest the following wording instead: "(Operating Reserve actions not exceeding the reserve sharing deployment period)". If the drafting team does not like the suggestion, then please clarify what is the basis for an odd # of minutes, instead of using more common 1/4 or full hour incriments? Under BAL-002, operating reserves can be supplied for up to 105 minutes (15 minutes for the disturbance plus 90 minutes). | Yes | | Yes | | |
| | Individual | Rex McDaniel | Texas-New Mexico Power company | | | No preference | | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that | Yes | | Yes | | This standard should not apply to ERCOT for the reason expressed in question 2. |

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| | | | | | | | | implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path (s). | | | | | |
| | Group | | | PPL Supply Group | Annette Bannon | | | R3. PPL suggests that the Purchasing/Selling Entities should be included in the listing of entities under Requirement R3. | | | | | |
| | Individual | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | | | Yes | The TOP is the responsible entity however, if the TOP operates in a single-control area region the establishment and applicability of TRM may have no reliabilty benefits. | | | | | | Brazos Electric believes that for a TOP operating in a single-control area region like ERCOT that the establishment of TRM may have no reliability benefits. The Applicability Section 4.1 for MOD-008 as written in this draft states "Transmission Operators that maintain TRM" could possibly be interpreted that this applies only to those TOPs who have a need to establish TRM because of the region it operates in. Otherwise in R1 it is reconmmended that an "if applicable" clause be inserted to address this issue. |
| | Group | | | Electric Service Delivery | Reza Ebrahimian | | | | | | | | These comments are filed on behalf of City of Austin d/b/a Austin Energy to address proposed NERC 5 MOD Standards. Austin Energy is a municipally owned electric utility and a transmission service provider with the Electric Reliability Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with no explicit transmission services being sold. Current ERCOT market rules allow open transmission access to all loads and resources. ERCOT will continue to operate as a Single Balancing Authority under Nodal market design. Accordingly, as explained in more detail below, the NERC 5 MOD Standards should not be applied to ERCOT and transmission service providers within ERCOT under its current or proposed Nodal market design. Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. Applicable definitions: According to NERC Reliability Standards Glossary of Terms, Available Transfer Capability (ATC) is defined as: "A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability (TTC) less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows". TTC is defined as: the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions. CBM is defined as the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. TRM also is a component of ATC defined as: that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. Comments: ERCOT is an interconnection and a region with no synchronous AC ties with any other interconnections. In July 2001, based on a deregulated Retail and restructured Wholesale Markets, the ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT market is designed such that there are no explicit transmission services being sold, hence, Available Transfer Capability (ATC) is not a measure used in a commercial activity within the ERCOT market. The current ERCOT market rules allow open transmission access to all eligible loads and resources without considering any specific Transmission Service Provider (TSP). Transmission facilities ratings are based upon individual branch element designs and in cases of dynamic ratings, ambient conditions are also considered. ERCOT has several DC ties and an asynchronous tie using a Variable Frequency Transformer (VFT); however, the associated interchange capabilities are planned and coordinated by the TSPs involved. The current ERCOT Zonal Market uses a flow based congestion management methodology to predict potential congestions in the Day Ahead and Adjustment Periods. During the operating period, generation shift factors are used to determine the dispatch needed to remain within the constrained limits. The local congestions are managed using full AC load flow analysis and unit specific redispatch. MOD-001-1 is entirely about methodology and calculation of ATC, therefore, this standard is not applicable to ERCOT. MOD-008-1 covers Transmission Reliability Margin (TRM) methodology calculation. Mathematically, ATC is defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin (CBM). Therefore, TRM also is not applicable to ERCOT. MOD-028-1 covers Area Interchange calculation Methodology. Since ERCOT is a single control area, Area Interchange calculation is not applicable. MOD-029-1 covers Rated System Path Methodology, which is used to |

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| | | | | | | | | | | | | | calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT. MOD-030-1 covers Flowgate methodology calculation of ATC, and therefore, is not applicable to ERCOT. ERCOT is currently transitioning to a Nodal Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a Security Constrained Economic Dispatch (SCED) approach to dispatch individual generating units and manage congestion. In the Nodal Market, ERCOT will still operate as a Single Balancing Authority. This again will not use ATC methodology, and aforementioned standards are not applicable to ERCOT in its ensuing Nodal Market. Therefore, Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. |
| | Individual | Aaron Staley | Orlando Utilities Commission | | | No preference | | | Yes | | Yes | | Requirements 1, 3, 4 and 5 are great exactly as they are. They are a good balance of standardization, disclosure and recognition that different parts of the transmission system function differently and are most sensitive to different factors. For Requirement #2, what is the reliability purpose for limiting the items that an entity can consider when establishing TRM? |
| | Individual | Rick Gonzales | New York Independent System Operator | | | Yes | | The NYISO has previously commented that R4 would require TRM to be recalculated more frequently than necessary for Transmission Operators whose TRM assumptions do not change frequently. Under the NYISO system, TRM values are stable over time and often do not change for periods longer than 13 months. The NYISO therefore renews its request that the SDT modify R4 to specify that TRM need not be re-established (or re-calculated) every 13 months to the extent that none of the underlying TRM inputs have changed. The SDT has previously revised R8 under MOD-001 in the same manner and there is every reason to make the same change to R4 under MOD-008. | Yes | | | | |

**Consideration of Comments on Draft Standard — MOD-008-1 — Project 2006-07**

The ATC Standards Drafting Team thanks all commenters who submitted comments on the draft standard MOD-008-1 – Transmission Reliability Margin Calculation Methodology. This standard was posted for a 30-day public comment period from April 16, 2008 through May 15, 2008. The stakeholders were asked to provide feedback on the standard through a special electronic Standard Comment Form. There were 33 sets of comments, including comments from 103 different people from approximately 60 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

There were some comments that led the drafting team to modify language to improve clarity, but none of the changes made by the drafting team changed the scope or intent of the requirements in the standard.

**Applicability**

- Transmission Operator or Transmission Service Provider - The April 2008 request for comments asked the industry to express their opinion on whether or not the Transmission Operator was the correct entity to be responsible for TRM. The results where 18 in favor of the TOP as the responsible entity, 5 against and 8 who had no preference. Some of the commenter's on this and other comment forms have asked for a "or" entry where the TOP or the TSP could be responsible. Current NERC standards have been written so that only one entity is (or multiple entities are) the responsible entity; so there is no question on who is accountable for a requirement. There has not yet been a standard written that established an "or" where it could be one or the other. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry. While the response to this questionnaire may not be a definitive survey of the industry preference, the team is going to go with the majority of the respondents and keep the standard as written, with the TOP responsible. For those for whom this does not result in a perfect fit with their current method of doing business, delegation of task, contract, adoption of another's work, an entity/regional/interconnection variance, or the use of a Joint Registration Entity may be appropriate means for meeting this requirement in addition to changing their current method.

- Several entities had questions and comments regarding the applicability statement in the standard and the language in some of the requirements. The team made no changes to the standard in regard to this but did paraphrase the applicability statement in some of the responses. The requirements in the standard only apply to those Transmission Operators that maintain a TRM value, and do not establish a requirement for an entity to maintain a TRM.

- Several entities have continued to express concern regarding the applicability of the ATC, TRM, and CBM standards. While the drafting team has attempted to write the standards in ways that are flexible and allow for organizational diversity, we note that FERC Order 890 makes reference to the use of Variances. Entities with non-traditional physical transmission markets or that have alternative ATC methodologies that meet or exceed the NERC ATC standards may wish to consider requesting one or more Variances related to these standards.

**Requirements**

- R1.1 - There were several respondents who asked questions about, made suggestions to or sought clarification on the list of uncertainties. The team modified the list slightly to further expand the list of transmission system topology differences, generation dispatch differences and to remove the timing requirement from the reserve sharing item.

- R2 - Several respondents questioned the reliability benefit of requirement 2, which limited the items that can be considered and forbids the use of elements of CBM. Requirement 2 is included in the standard as a direct response to the request of FERC in Order 890 that specified the standard should include a list of uncertainties and should restrict the utilities from straying from that list, or using any element of CBM in TRM.

**Compliance**

- The industry opinion regarding Violation Risk Factors for this standard as expressed in this request for comments indicates a preference 23 to 1 in favor of the current Violation Risk Factors, which are lower. The team once again iterates that it believes that per the current NERC definitions of violation risk factors, no part of this standard (TRM) if not correctly applied would have a direct affect on the state or capability of the bulk power system.

- The industry opinion regarding Violation Severity Levels for this standard as expressed in this request for comments indicates a preference 20 to 3 in favor of the current Violation Severity Levels. One commenter expressed concern on R2 having only a single VSL of severe. The drafting team believes that if a requirement is a pass/fail, and therefore has only one "VSL" that VSL has to be severe. VSL srefer to how badly a requirement was missed, not to the criticality of that particular requirement. Violation Risk Factors address the criticality of a particular element.

- Two other commenters expressed concerns on double jeopardy in the standard, or having a single event result in multiple violations. While this is an issue that has to be addressed by the compliance side of NERC and its policies, the team did review the standards with this concept in mind. As a result of this review the team revised the wording on the VSL's for Requirement 5 to reinforce that an incorrect value developed under R4, that was properly made available per R5, is not a violation of R5.

**Concepts**

- Several entities had questions and comments regarding the team developing a universal (mandatory) or default (recommended) TRM value. The team does not believe the have sufficient information or time in the process to gather the information, to establish a universal TRM. The transmission system varies between regions and even within regions and to arbitrarily select a TRM value or method would result in some areas suffering either an inappropriate decrease in reliability, an unnecessary decrease in market access, and more likely a mix of these problems across the entities that follow NERC standards. By the same measure the team has declined to establish a default or recommended TRM methodology or percentage, again because the team felt that lacked sufficient technical information to provide a value that was not arbitrary. The team has encouraged several respondents to pursue a white paper request or follow up SAR request to develop a dedicated team for looking at this issue.

- Several commenters questioned the removal of the tie between TRM and long term planning. The other MOD standards tie parts of the ATC development process to appropriate parts of the planning process to insure consistency and fair treatment. TRM since it applies to all users of a path will insures equal treatment to all users. All FERC Jurisdictional entities are required to have an Attachment K (planning process), this process allows market participants access to the utilities planning process, and thereby the opportunity to questions the entity on their TRM and how it is accounted for in their long term plans.

**Implementation**

- A popular comment related to the implementation plan. Because MOD-008 can be implemented independent of the other standards and because MOD-008 being implemented in one area and not another would not cause a coordination problem, the standard team is keeping the current implementation language.

**Variance**

The SDT believes it may be helpful to the industry to review the process for Variances. The Variance process can work either concurrent with or independent of the development of a standard. Because the drafting team working on a particular standard is likely to already have the necessary expertise to participate in the development of the Variance, concurrent development is generally more efficient. However, this may not always be practical; in this case, standards drafting may proceed, and even complete, prior to the development and approval of Variances. In this case, entities should seek to develop those Variances and seek their approval prior to the effective date of the standard. An entity is not exempt from meeting the requirements of the standard if the effective date has passed and that entity is in the process of developing a Variance.

The NERC process allows for three different types of variances:

- An Entity Variance
- A Regional Variance less than an Interconnection
- A Regional Variance on Interconnection-Wide basis

The NERC Rules of Procedure describe an Entity Variance as follows:

> Entity Variance — Any variance from a NERC reliability standard that is proposed to apply to one entity or a subset of entities within a limited portion of a regional entity, such as a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users, shall be approved through the regular standards development process defined in the NERC Reliability Standards Development Procedure and shall be made part of the applicable NERC reliability standard.

Entities seeking an Entity Variance should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requester is addressing the reliability goals of the standard. The ballot body is comprised of any member of the Registered Ballot Body that is interested and registers to join the ballot pool. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe a Regional Variance Less Than an Interconnection as follows:

> Any regional variance from a NERC reliability standard that is proposed to apply for a regional entity, but not for an interconnection, shall be approved through the NERC Reliability Standards Development Procedure, except that only members of the registered ballot body located in the affected interconnection shall be permitted to vote; and the variance shall be made part of the applicable NERC reliability standard.

Entities seeking a Regional Variance Less Than an Interconnection should draft a SAR to request that Variance. In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately). In both cases, the Variance will be compared to the standard to ensure the requestor is addressing the reliability goals of the standard. The ballot body is comprised of any interested entities that that have registered with NERC and is a user, owner, or operator of facilities located within the interconnection in which the region requesting the Variance is located. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe a Regional Variance on an Interconnection-wide Basis as follows:

> An interconnection-wide regional variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the NERC reliability standard. NERC shall rebuttably presume that a regional variance from a NERC reliability standard that is developed, in accordance with a procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Entities seeking a Regional Variance on an Interconnection-wide Basis should draft that Variance using the regional standards development process described in the region's delegation agreement. In that Variance, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Once approved through the regional standards development process, the Variance should be brought to NERC for filing with the appropriate regulatory authorities.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving these standards forward to posting for pre-ballot review.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standard can be viewed in their original format at:

[http://www.nerc.com/~filez/standards/MOD-V0-Revision.html](http://www.nerc.com/~filez/standards/MOD-V0-Revision.html)

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

## Index to Questions, Comments, and Responses

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Anita Lee (G3) | AESO | | x | | | | | | | | |
| 2. | Ken Goldsmith (G7) | ALTW | | | | x | | | | | | |
| 3. | Helen Stines (G1) | Alcoa Power Generating, Inc. | x | | x | | | | | | | |
| 4. | Eugene Warnecke (G1) | Ameren | x | | x | | | | | | | |
| 5. | Jason Shaver | American Transmission Company | x | | | | | | | | | |
| 6. | Jerry Smith (G2) | APS | x | | | | | | | | | x |
| 7. | Dave Rudolph (G7) | BEPC | x | | x | | x | x | | | | |
| 8. | Chris Bradley (G1) | Big Rivers Electric Cooperative | x | | x | | | | | | | |
| 9. | Denise Koehn (G6) | Bonneville Power Administration | x | | x | | x | x | | | | |
| 10. | Mike Viles (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 11. | Abbey Nulph (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 12. | Don Watkins (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 13. | Patrick Roechelle (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 14. | Kammy Rogers-Holiday (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 15. | Robin Chung (G6) | Bonneville Power Administration | | | x | | x | x | | | | |
| 16. | Rebecca Berdahl (G6) | Bonneville Power Administration | | | x | | | | | | | |
| 17. | Susan Millar (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 18. | Todd Miller (G6) | Bonneville Power Administration | | | x | | x | x | | | | |
| 19. | Elizabeth Loebach (G6) | Bonneville Power Administration | x | | | | | | | | | |
| 20. | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | x | | | | x | | | | | |
| 21. | Dave Lunceford (G2) | California ISO | | x | | | | | | | | x |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 22. | Brent Kingsford (G3) | California ISO | | x | | | | | | | | |
| 23. | Paul Bleuss (G5) | California ISO | | x | | | | | | | | |
| 24. | Frank Cumpton | California ISO | | x | | | | | | | | |
| 25. | Paul Rocha | CenterPoint Energy | x | | | | | | | | | |
| 26. | Greg Rowland | Duke Energy Corporation | x | | x | | x | x | | | | |
| 27. | Reza Ebrahimian | Electric Service Delivery | x | | | | | | | | | |
| 28. | Jim Case (G5) | Entergy Services, Inc. | x | | | | | | | | | |
| 29. | Narinder K. Saini (G8) | Entergy Services, Inc. | x | | | | | | | | | |
| 30. | Joachim Francois (G1) (G8) | Entergy Services, Inc. | x | | x | | | | | | | |
| 31. | Ed Davis (G8) | Entergy Services, Inc | x | | | | | | | | | |
| 32. | George Bartlett (G8) | Entergy Services, Inc | x | | | | | | | | | |
| 33. | Lynna Estep (G8) | Entergy Services, Inc | x | | | | | | | | | |
| 34. | Michelle Bourg (G8) | Entergy Services, Inc | x | | | | | | | | | |
| 35. | Matt McNeece (G8) | Entergy Services, Inc | x | | | | | | | | | |
| 36. | Cameron Warren (G8) | Entergy Services, Inc | x | | | | | | | | | |
| 37. | Joachim Francois (G8) | Entergy Services, Inc | x | | | | | | | | | |
| 38. | Joachim Francois (G1) | Entergy Services, Inc. | x | | x | | | | | | | |
| 39. | Jack Cashin/Barry Green | EPSA | | | | | x | x | | | | |
| 40. | H. Steven Myers (I) (G3) (G5) | ERCOT ISO | | x | | | | | | | | |
| 41. | Eric Mortenson | Exelon | x | | x | | | | | | | |
| 42. | Doug Hohlbaugh | FirstEnergy | x | | x | | x | | | | | |
| 43. | Dave Folk | FirstEnergy | x | | x | | x | | | | | |
| 44. | Rob Martinko | FirstEnergy | x | | x | | x | | | | | |
| 45. | Sam Ciccone | FirstEnergy | x | | x | | x | | | | | |
| 46. | Ralph Anderson (G5) | FMPA | | | | x | | | | | | |
| 47. | Earl Fair | Gainesville Regional Utilities | x | | x | | x | | | | | |
| 48. | Ross Kovacs (G1) | Georgia Transmission Corp. | x | | | | | | | | | |
| 49. | Joseph Knight (G7) | GRE | x | | x | | x | x | | | | |
| 50. | David Kiguel (G4) | Hydro One Networks | x | | x | | | | | | | |
| 51. | Alessia Dawes | Hydro One Networks | x | | x | | | | | | | |
| 52. | Roger Champagne (G4) | Hydro Quebec TransEnergie | x | x | | | | | | | | |
| 53. | Ron Falsetti (G3) (I) | IESO | | x | | | | | | | | |
| 54. | Matt Goldberg (G3) | ISO-New England | | x | | | | | | | | |
| 55. | Kathleen | ISO-New England | | x | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Goodman (G4) | | | | | | | | | | | |
| 56. | Jim Useldinger | Kansas City Power & Light | x | | | | | | | | | |
| 57. | Eric Ruskamp (G7) | LES | x | | x | | x | x | | | | |
| 58. | Maria Neufeld | Manitoba Hydro | x | | x | | x | x | | | | |
| 59. | Joe DePoorter (G7) | MGE | | | x | x | x | x | | | | |
| 60. | John Harmon | MISO | | x | | | | | | | | |
| 61. | Bill Phillips (G3) | MISO | | x | | | | | | | | |
| 62. | Jason Marshall (G5) | MISO | | x | | | | | | | | |
| 63. | Terry Bilke (G7) | MISO | | x | | | | | | | | |
| 64. | Carol Gerou (G7) | MP | x | | x | | x | x | | | | |
| 65. | Larry Brusseau (G7) | MRO | | | | | | | | | | x |
| 66. | Mike Brytowski (G7) | MRO | | | | | | | | | | x |
| 67. | Tom Mielnik (G7) | MRO NERC Standards Review Subcommittee | x | | x | | x | x | | | | |
| 68. | Jerry Tang (G1) | Municipal Electric Auth. of GA | x | | x | | | | | | | |
| 69. | Rick Gonzales | New York Independent System Operator | | x | | | | | | | | |
| 70. | Greg Campoli (G4) | New York ISO | | x | | | | | | | | |
| 71. | Ralph Rufrano (G4) | New York Power Authority | x | | | x | x | x | | | x | |
| 72. | Rick White (G4) | Northeast Utilities | x | | | x | | | | | | |
| 73. | Guy V. Zito (G4) | NPCC | | | | | | | | | | x |
| 74. | Alan Adamson (G4) | NYSRC | | | | | | | | | | |
| 75. | Jim Castle (G3) | NYISO | | x | | | | | | | | |
| 76. | Greg Ward / Darryl Curtis | Oncor Electric Delivery | x | | | | | | | | | |
| 77. | Aaron Staley | Orlando Utilities Commission | x | | x | | x | | | | x | |
| 78. | Richard Kafka | Pepco Holdings, Inc. | x | | x | | x | x | | | | |
| 79. | Patrick Brown (G3) (I) | PJM | | x | | | | | | | | |
| 80. | John Cummings (G4) | PPL EnergyPlus | | | | | | x | | | | |
| 81. | Jon Williamson (G4) | PPL EnergyPlus | | | | | | x | | | | |
| 82. | Mark Hemibach (G4) | PPL Generation/PPL EnergyPlus | | | | | x | x | | | | |
| 83. | Annette Bannon | PPL Supply Group | x | | x | | x | x | | | | |
| 84. | Phil Creech (G1) | Progress Energy - Carolinas | x | | x | | | | | | | |
| 85. | Phil Riley | Public Service Commission of South Carolina | | | | | | | | | x | |
| 86. | W. Shannon Black (G2) | Sacramento Municipal Utility District | | | x | | | | | | | |
| 87. | Pat Huntley (G1) | SERC | | | | | | | | | | x |
| 88. | John Troha (G1) | SERC | | | | | | | | | | x |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 89. | Doug Bailey (G1) | SERC Available Transfer Capability Working Group (ATCWG) | x | | x | | | | | | x | |
| 90. | Vicky Budreau (G1) | So. Carolina Public Service Auth. | x | | x | | | | | | | |
| 91. | Al McMeekin (G1) | South Carolina Electric & Gas | x | | x | | | | | | | |
| 92. | Stan Shealy (G1) | South Carolina Electric & Gas | x | | x | | | | | | | |
| 93. | Jim Griffith (G1) | Southern Co. | x | | x | | | | | | | |
| 94. | DuShaune Carter (G1) | Southern Co. | x | | x | | | | | | | |
| 95. | Kevin Bates | Southwest Power Pool | | x | | | | | | | | |
| 96. | Charles Young (G3) | Southwest Power Pool | | x | | | | | | | | |
| 97. | Chuck Falls (G2) | SRP | x | | | | | | | | | x |
| 98. | Rex McDaniel | Texas-New Mexico Power Company | x | | | | | | | | | |
| 99. | Brian Evans Mongeon G4) | Utility Services, LLC | | | | | | x | | | | |
| 100. | Ji Haigh | WAPA | x | | | | | x | | | | |
| 101. | Neal Balu (G7) | WPS | | | x | x | x | x | | | | |
| 102. | Pam Oreschnick (G7) | Xcel Energy | x | | x | | x | x | | | | |
| 103. | Alice Druffel | Xcel Energy | x | | x | | x | x | | | | |

I — Individual
G1 — SERC Available Transfer Capability Working Group
G2 — WECC Market Interface Committee / Sub Commtt / ATC Task Force
G3 — ISO RTO Council/Standards Review Committee (SRC)
G4 — NPCC Regional Standards Committee
G5 — NERC RTO SDT
G6 — BPA
G7 — MRO Standards Review Committee
G8 — Entergy Services

1. Some entities have indicated they believe the Transmission Operator should not be an applicable entity in the TRM standard (MOD-008). The Drafting Team believes that the Transmission Operator is the appropriate entity since the Transmission Operator is ultimately responsible for operating a reliable system while using all Transmission Service Providers' calculated available capability. The drafting team also believes that the Transmission Operator can, via mutual agreement, delegate these tasks to other entities (such as Transmission Service Providers, ISOs, or RTOs). Do you believe the Transmission Operator is the correct responsible entity for the tasks it has been assigned in MOD-008? If "No," please identify requirements where the Transmission Operator is incorrect and specify who the correct entity should be.

**Summary Consideration:**

The April 2008 request for comments asked the industry to express its opinion on this issue. The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Some of the commenters on this and other comment forms have asked for an "or" entry where the TOP or the TSP could be responsible. Current NERC standards have been written so that only one entity is (or multiple entities are) the responsible entity; so there is no question on who is accountable for a requirement. There has not yet been a standard written that established an "or" where it could be one or the other. Given that restriction, the requirement has to be written for only one entity.

It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry. While the response to this questionnaire may not be a definitive survey of the industry preference, the team is going to go with the majority of the respondents and keep the standard as written, with the TOP responsible. For those for whom this does not result in a perfect fit with their current method of doing business, delegation of task, contract, adoption of another's work, an entity/regional/interconnection variance, or the use of a Joint Registration Entity may be appropriate means for meeting this requirement in addition to changing their current method.

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| Xcel Energy | No | We feel that the applicability should apply to the TSP, recognizing that the TSP will require input from the TOP. To further explain, the ATC/AFC methodology is primarily a mechanism for the TSP to sell/provide transmission service in a manner that ensures the transmission system is secure .A TOP however will utilize SOLs and IROLs in the operations of the transmission system, and do not necessarily have to be the same as the ATC/AFC components. As an example, in the selling of service, TRM will not be sold so the limit =TTC-TRM. However the TOP may operate into the TRM during real-time operations and not hold this margin, but honor the true system limit. As another example, there are interdependent flowgates where the ATC components will be based on the most conservative combination, but the system will be operated to minimize restrictions. This may result in a sliding operating limit for the TOP based on actual conditions, while a TSP has to use the most conservative limits for ATC/AFC. |
| **Response:** The April 2008 request for comments asked the industry to express their opinion on this issue The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is | | |

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| no allowance for one entity “or” another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. TRM applies only to the calculation of ATC, and is not an operational requirement on the TOP that would restrict its actions. | | |
| Kansas City Power & Light | No | The Transmission Service Provider should also be listed as an appropriate entity along with the TOP in all requirements, so that either entity could perform this function. |
| **Response:** The April 2008 request for comments asked the industry to express their opinion on this issue The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity “or” another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. | | |
| FirstEnergy | No | Within many RTO areas it is the TSP who maintains the TRM Methodology and assures its appropriate implementation while calculating ATC or AFC. This is the case in a large portion of the continent and a standard should not be written in a way that would knowingly require an assignment delegation for a large number of potential responsible entities. Assigning the applicability in this standard to the TSP would work for non-market areas of the continent since in those areas the TOP most likely serves as its own TSP. |
| **Response:** The April 2008 request for comments asked the industry to express their opinion on this issue The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity “or” another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. | | |
| AEP | No | The Transmission Service Provider is the applicable entity. |
| **Response:** The April 2008 request for comments asked the industry to express their opinion on this issue. The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity “or” another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. | | |
| Gainesville Regional Utilities | No | I would suggest the TSP and let that entity negotiate, via mutual agreement, to delegate these task. |

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| **Response:** The April 2008 request for comments asked the industry to express their opinion on this issue. The results where 18 in favor of the TOP as the responsible entity, 5 against and 8 who had no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. | | |
| American Transmission Company | Yes | We agree that the Transmission Operator is the correct entity but are concerned with the inserted exclusion. Why did the SDT insert the exclusion in this draft of the Standard? (No previous drafts contained this exclusion.)How would a TOP go about notifying NERC that MOD-008 is not applicable to them? How would NERC or the Regions know if something changed and the TOP is now performing TRM? When would this standard apply to a TOP that does not currently perform a TRM? An alternate approach is to have TOPs that do not perform TRMs, Certify yearly that they do not perform TRMs and therefore satisfy MOD-008-1. |
| **Response:** The April 2008 request for comments asked the industry to express their opinion on this issue. The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. | | |
| Brazos Electric Power Cooperative, Inc. | Yes | The TOP is the responsible entity however, if the TOP operates in a single-control area region the establishment and applicability of TRM may have no reliability benefits. |
| **Response:** Thank you for your supportive comment. | | |
| WECC Market Interface Committee ATC Task Force | Yes | |
| Exelon | Yes | |
| NPCC Regional Standards Committee | Yes | |
| WECC Market Interface Committee / Sub Commtt / ATC | Yes | |

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| Task Force | | |
| PJM | Yes | |
| Duke Energy Corporation | Yes | |
| Bonneville Power | Yes | |
| Pepco Holdings, Inc | Yes | |
| ISO RTO Council/Standards Review Committee (SRC) | Yes | |
| MRO NERC Standards Review Subcommittee | Yes | |
| Ontario IESO | Yes | |
| Hydro One Networks | Yes | |
| Entergy Services Inc. | Yes | |
| The Midwest ISO | Yes | |
| Southwest Power Pool | Yes | |
| New York Independent System Operator | Yes | |
| Public Service Commission of South Carolina | No preference | |
| Orlando Utilities Commission | No preference | |
| Oncor Electric | No | |

| Organization/Group | Question 1: | Question 1 Comments: |
| --- | --- | --- |
| Delivery | preference | |
| Texas-New Mexico Power company | No preference | |
| Manitoba Hydro | No preference | |
| SERC ATCWG | No preference | |
| EPSA | No preference | |
| ERCOT ISO | No preference | |

2. The drafting team modified some requirements and associated measures to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct. Incorrect Requirement(s) or Measure(s):

**Summary Consideration:**

Several entities had questions on requirements applying to TOP's or TSP's. A summary of the team's resolution is presented in the "summary consideration" for question #1.

Several entities had questions and comments regarding the applicability statement in the standard and the language in some of the requirements. The team made no changes to the standard in regard to this, but did paraphrase the applicability statement in some of the responses. The requirements in the standard only apply to those TOP's who maintain a TRM value, and do not establish a requirement for an entity to maintain a TRM.

Several entities had questions and comments regarding the team developing a universal (mandatory) or default (recommended) TRM value. The team does not believe it has sufficient information or time in the process to gather the information, to establish a universal TRM. The transmission system varies between regions and even within regions; to arbitrarily select a TRM value or method would result in some areas suffering either an inappropriate decrease in reliability, an unnecessary decrease in market access, and more likely a mix of these problems across the entities that follow NERC standards. By the same measure, the team has declined to establish a default or recommended TRM methodology or percentage, again because the team felt that it lacked sufficient technical information to provide a value that was not arbitrary. The team has encouraged several respondents to pursue a white paper request or follow up SAR request to develop a dedicated team to look at this issue.

Several commenters questioned the removal of the tie between TRM and long term planning. The other MOD standards tie parts of the ATC development process to appropriate parts of the planning process to insure consistency and fair treatment. TRM, since it applies to all users of a path, will insure equal treatment to all users. All FERC Jurisdictional entities are required to have an Attachment K (planning process). This process allows market participants access to the utilities' planning processes, and thereby the opportunity to question an entity on its TRM and how it is accounted for TRM in its long term plans.

Several respondents questioned the reliability benefit of requirement 2, which limits the items that can be considered and forbids the use of elements of CBM. Requirement 2 is included in the standard as a response to the directive in FERC Order 890 that specified the standard should include a list of uncertainties and should restrict the utilities from straying from that list, or using any element of CBM in TRM.

There were several respondents who asked questions about, made suggestions to, or sought clarification on the list of uncertainties. The team modified the list slightly to further expand the list of transmission system topology differences, generation dispatch differences and to remove the timing requirement from the reserve sharing item.

| Organization/Group | Question 2 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| EPSA | We believe that the former requirement R1.2 which established the consistency between planning assumptions and those used in calculation TRM was appropriate and do not agree with its deletion.<br>**Response:** The TRM standards should apply only to the calculation of TRM and its application for the determination of ATC. The team removed the consistency clause in response to comments and supports this with three reasons. The first being that any requirement linking TRM methodology with planning assumptions would need to be in the planning standard, to do otherwise is to create the potential for conflicting standards where meeting both is not possible. Second, the entity's open planning process (as documented in its OATT Attachment K) provides opportunity to address any unfairness between the TRM and its planning process. Finally, TRM is intended to be based on conditions other than those expected, so requiring assumptions to be consistent with those used in planning of operations would be contrary to the goal of TRM.<br><br>In R3, the previous draft of the standard required sharing of "underlying documentation, work papers and load flow base cases". In the current draft, the latter two of the listed items have been deleted. It is acceptable to us if this is done merely because they are deemed to be redundant as they are included within the meaning of "underlying documentation". If this was not the intent of the drafters, we would disagree with this change as those are items that would be required in order to reproduce the studies that have led to the posted ATC values.<br>**Response:** The intent of the requirement is that "underlying documentation" would include work papers, load flow cases and any other reference material used to create the TRM. |
| **Response:** Please see in-line responses. | |
| WECC Market Interface Committee / Sub Commtt / ATC Task Force | The Team suggests moving the final phrase of the proposed R3 Requirement to the beginning of the sentence to add clarity. (This is a non-substantive change.) The new R would read: No more than 30 calendar days after receiving a request, each Transmission Operator shall make available its TRMID, and if requested, its underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request for that data: |
| **Response:** The SDT has tried to use a consistent structure for the requirements, and believes the suggested change would not add sufficient clarity to warrant the change at this time. | |
| Kansas City Power & Light | Add "or Transmission Service Provider" after Transmission Operator in all requirements. |

| Organization/Group | Question 2 - Incorrect Requirement(s) or Measure(s): |
| --- | --- |
| **Response:** The April 2008 request for comments asked the industry to express their opinion on this issue. The SDT received 18 comments in favor of the TOP as the responsible entity, 5 comments against and 8 comments that specified no preference. Current NERC standards are written so that only one entity is (or multiple entities are) the responsible entity; so that there is no question on who is accountable for a requirement, there is no allowance for one entity "or" another. Given that restriction, the requirement has to be written for only one entity. It is obvious that neither selection (TSP or TOP) provides a perfect fit for the entire industry, and for those for whom this does not work a delegation of task, an entity variance, or the use of a Joint Registration Entity may be appropriate. | |
| WECC Market Interface Committee ATC Task Force | The Team suggests moving the final phrase of the proposed R3 Requirement to the beginning of the sentence to add clarity. (This is a non-substantive change.)The new R would read :No more than 30 calendar days after receiving a request, each Transmission Operator shall make available its TRMID, and if requested, its underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request for that data: |
| **Response:** The SDT has tried to use a consistent structure for the requirements, and believes the suggested change would not add sufficient clarity to warrant the change at this time. | |
| ERCOT ISO | Requirement 1:I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) and with TRM shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: "<br><br>Requirement 2:I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) and with TRM shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. "<br><br>Requirement 3: I suggest modifying the requirement to state: "Each Transmission Operator with ATC Path(s) and with TRM shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request." |
| **Response:** Because the applicability already exempts any entities that do not maintain TRM from the standard, these changes will not be adopted. | |
| Exelon | In MOD-008-1 the following requirement was removed: R1.2.A A statement to confirm that it shall use assumptions in calculating TRM that are consistent with those assumptions that are used in the Transmission planning process for the time period studied". The NERC ATCWG reached conclusion on the following rule as they were developing the "Transmission Capability Margins and Their Use in ATC Determination" white paper which discusses the reliability margins of TRM and CBM: A Transmission Provider's ATC/AFC calculations, and associated margins, must be consistent with the Transmission Owners and Public Power Entities documented |

| Organization/Group | Question 2 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| | Planning Criteria. This rule was incorporated into the "Transmission Capability Margins and Their Use in ATC Determination? white paper dated June 17, 1999 as demonstrated in the following exert:? ?The methodology used to derive TRM and its components must be documented and consistent with published planning criteria, and must not account for uncertainties already accounted for elsewhere in the ATC determination. A TRM is considered consistent with published planning criteria if the same components that comprise it are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process? AFC/ATC calculations must be consistent with each Transmission Owner's planning criteria in order to maintain reliability. AFC/ATC calculations must not be subject to evaluation scenarios that exceed or are "beyond" the applicable planning criteria. For example, if the most extreme event a Transmission Owner plans for were single contingencies, it would be inconsistent with the applicable planning criteria to evaluate a transmission service request to meet a double contingency test. In this instance, evaluating a transmission service request using double contingency analysis would be in conflict with the planning criteria and would not be compatible with the reliability requirements used to serve native connected load. In an ATC calculation the following components determine the loading on a flowgate for the period of time under evaluation:<br>1. Base Case Flows (which recognizes the forecasted load connected to the transmission network and planned system topology)<br>2. Impacts of existing transmission service reservations -- both positive and negative (i.e. counterflow)<br>3. TRM (consistent with applicable Planning Criteria)<br>4. CBM (consistent with applicable Planning Criteria) When these four components are applied to a flowgate the result is a calculated AFC. If the resultant AFC is negative, the result indicates that the flowgate is projected to be overloaded because of the preexisting commitments (i.e. the four components listed above). In some cases negative AFC values exist for future years preventing transmission customers from obtaining transmission reservations for these future time periods.<br>The inconsistency between Transmission Provider's AFC/ATC calculations and the Transmission Owner's Planning criteria becomes evident when the Transmission Owner internal planning processes does not result in identification of system deficiencies requiring system expansion — even on Flowgate determined by the Transmission Provider to have negative AFC values far into the future. The likely cause of this discrepancy is that the TO is not applying the same scenario, including the same transmission uses (i.e. confirmed reservations), or consistent margins (TRM/CBM) in its internal planning process. |
| **Response:** The relationship between an entity's TTC/TFC/AFC/ATC/CBM and other calculations and the operations and transmission planning process are discussed in the responses to the comments submitted on those other applicable MOD standards. The TRM standard was written to | |

| Organization/Group | Question 2 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| only apply to the calculation of TRM and its application for the determination of ATC. The team removed the consistency clause in response to comments and supports this with three reasons. The first being that any requirement linking TRM methodology with planning assumptions would need to be in the planning standard, to do otherwise is to create the potential for conflicting standards where meeting both is not possible. Second, the entity's open planning process (as documented in its OATT Attachment K) provides opportunity to address any unfairness between the TRM and its planning process. Finally, TRM is intended to be based on conditions other than those expected, so requiring assumptions to be consistent with those used in planning of operations would be contrary to the goal of TRM. | |
| FirstEnergy | R2 – This requirement states "Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM." We recommend replacing "only use" with "include" since "only use" presumes that the list of uncertainties stated in the standard are all inclusive of all factors that a TOP/TSP may want to address in TRM. The requirement explicitly states that CBM should not be included in TRM, so making this change should not create an opportunity for double dipping on CBM. |
| **Response:** Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements that do not allow the use of uncertainty other then those in the list. The Order also requested that the standard specify that TRM not include elements of CBM. | |
| PJM | Although the SDT had the appropriate Team to establish a default percentage for TRM, the FERC deadline did not allow enough time to complete this portion of the requirement. Since TRM is a reliability margin, PJM encourages the Team to provide what ever input it currently has in a ?parking lot? for a possible future Team to undertake the development activity. There should be a default percentage to be used without requiring specific documentation, work papers and load flow cases if a straight percentage such as 5% is used. Additional information would be required only if a greater percentage is used. |
| **Response:** The drafting team, in numerous discussions, examined the use of a fixed percentage rather then specifying the areas of uncertainty. The standard as it is currently written does not require or forbid the use of a fixed percentage as a margin, but does require that the entity explain the rationale for the percentage. Additionally the standard requires that the margin represent only the areas of uncertainty specified in R1 and not include any items included in CBM. We encourage PJM to draft a SAR if further development in TRM is desired and/or file for a variance that more clearly permits a flat percentage. | |
| Pepco Holdings, Inc | PHI supports the comments of PJM and will not submit duplicate comments |
| **Response:** Please see PJM response. | |
| Oncor Electric Delivery | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would |

<table>
<tr><th>Organization/Group</th><th>Question 2 - Incorrect Requirement(s) or Measure(s):</th></tr>
<tr><td></td><td>add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s).</td></tr>
<tr><td colspan="2">Response: This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt form this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>Gainesville Regional Utilities</td><td>R2: Why limit what items can be considered in developing TRM? What reliability purpose could it possibly serve? R1,3,4 & 5 are OK as presented.</td></tr>
<tr><td colspan="2">Response: Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements that do not allow the use of uncertainty other then those in the list. The Order also directed that the standard specify that TRM not include elements of CBM.</td></tr>
<tr><td>MRO NERC Standards Review Subcommittee</td><td>1. The MRO believes that M1 should be revised to delete the words "all" from the phrase "all specified information?" This use of "all" seem to be unnecessary and may result in over-the-top auditing.<br>Response: The SDT intends for the measure to determine if all sub-requirements were addressed, not if all bullets in R1.1 were included. Each bullet in R1.1 is only required if used, as described in the sub-requirement.<br><br>2. The MRO commends the SDT on deleting R1.2.A and R1.5. The MRO believes that these former requirements were unnecessary and not reliability related and that the changes are significant improvements to the standard.<br>Response: Thank you for your supportive comment.<br><br>3. The MRO is asking for clarification in R1.1 on "Reserve sharing requirements". The MRO is assuming that this is not non-operating reserves such as planning reserves.<br>Response: MRO is correct; this is not intended to cover planning reserves. This was not meant to be specific to a particular arrangement, but to cover any generation reserve sharing agreement that might require a margin on the</td></tr>
</table>

| Organization/Group | Question 2 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| | transmission system for delivery.<br><br>4. R1.1, bullet 7 reads: Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window). The "59-minute window" conflicts with BAL-002. Under BAL-002, operating reserves can be supplied for up to 105 minutes (R4.2 15 minutes for the disturbance plus R6.2 90 minutes). We suggest the following wording instead: "(Operating Reserve actions not exceeding the operating reserve sharing deployment period)".<br>**Response:** The SDT will not comment on whether or not the statement regarding provision of reserves for up to 105 minutes is correct or incorrect. The team eliminated the 59-minute limitation since this was not meant to identify a specific arrangement but a category of arrangements. |
| 3. **Response:** Please see in-line responses. | |
| Entergy Services Inc. | R2 – Entergy recommends deleting the phrase "and shall not include any of the components of Capacity Benefit Margin (CBM). |
| **Response:** Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements that do not allow the use of uncertainty other then those in the list. The order also directed that the standard specify that TRM not include elements of CBM. | |
| The Midwest ISO | R1.1 – Please clarify the uncertainty components below: o Allowances for simultaneous path interactions (how is it different from loop flow above?)<br>**Response:** Different parts of the country refer to these concepts using a variety of terms with a variety of definitions ranging from overlapping definitions to distinct and exclusive definitions. Listing of both allows for greater flexibility since neither is a defined term.<br><br>Short-term System Operator response (Does this exclude reserve sharing requirements?).<br>**Response:** "Reserve sharing requirements" is listed as the next sub bullet under "System Operator Response", so it doesn't matter if short term system operator response includes reserve sharing requirement – provided the values are not duplicated.<br><br>R2 — This requirement as it is written doesn't allow the Transmission Operators to include any other uncertainties other than from R1.1. If R1.1 is not trying to list the complete set of uncertainties, we recommend to revise R2 to "Each Transmission Operator shall not include any of the components of Capacity Benefit Margin (CBM)"<br>**Response:** Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements that do not allow the use of uncertainty other then those in the list. The order |

| Organization/Group | Question 2 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| | also directed that the standard specify that TRM not include elements of CBM. |
| **Response:** Please see in-line responses. | |
| American Transmission Company | Modification Requirement 1: Each TOP shall prepare and keep current a Transmission Reliability Margin Implementation Document (TRMID) that includes the following information: The phrase "as a minimum" is not needed because the TOP has to include all sub-requirement in order to meet requirement 1. Any information above that which is listed is outside of NERC's audit<br>**Response:** While the requirement specifies that you can only use the listed items to determine TRM, entities may provide additional information beyond that which is required in the TRMID (e.g., examples of calculations). Using the phrase "as a minimum" insures an entity can include the additional information without a compliance issue.<br><br>Modifications to Requirement 4: Each TOP shall establish TRM values in accordance with the TRMID at least once every 13 months.<br><br>Modification to Requirement 5: The TOP shall provide the TRM values to its TSP(s) and TP(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. The phrase "using TRM" conflicts with Requirements 1 - 3. In addition we believe the deletion aligns with our comment on the applicability section.<br>**Response:** We have included this in R4 and R5 to further emphasize that TOPs without TRM don't need to do this, even though it is redundant with the applicability section.<br><br>M1 should be revised to delete the words "all" from the phrase "all specified information?" to avoid being overly inclusive.<br>**Response:** The SDT intends for the measure to determine if all sub-requirements were addressed, not if all bullets in R1.1 were included. Each bullet in R1.1 is only required if used, as described in the sub-requirement. |
| **Response:** Please see in-line responses. | |
| Xcel Energy | R1.1, bullet 7 reads: Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window). The "59-minute window" seems arbitrary and potentially conflicting. We suggest the following wording instead: "(Operating Reserve actions not exceeding the reserve sharing deployment period)". If the drafting team does not like the suggestion, then please clarify what is the basis for an odd # of minutes, instead of using more common 1/4 or full hour increments? Under BAL-002, operating reserves can be supplied for up to 105 minutes (15 minutes for the disturbance plus 90 minutes). |
| **Response:** The SDT will not comment on whether or not the statement regarding provision of reserves for up to 105 minutes is correct or incorrect. | |

| Organization/Group | Question 2 - Incorrect Requirement(s) or Measure(s): |
| --- | --- |
| The team eliminated the 59-minute limitation since this was not meant to identify a specific arrangement but a category of arrangements. | |
| Texas-New Mexico Power company | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). |
| **Response:** This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose maintain TRM, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| PPL Supply Group | R3. PPL suggests that the Purchasing/Selling Entities should be included in the listing of entities under Requirement R3. |
| **Response:** Purchasing and Selling entities in the opinion of the team do not have a transmission reliability need to access those items. This is an openness and transparency issue that would best be addressed in an entity's OATT or in business practices. | |
| New York Independent System Operator | The NYISO has previously commented that R4 would require TRM to be recalculated more frequently than necessary for Transmission Operators whose TRM assumptions do not change frequently. Under the NYISO system, TRM values are stable over time and often do not change for periods longer than 13 months. The NYISO therefore renews its request that the SDT modify R4 to specify that TRM need not be re-established (or re-calculated) every 13 months to the extent that none of the underlying TRM inputs have changed. The SDT has previously revised R8 under MOD-001 in the same manner and there is every reason to make the same change to R4 under MOD-008. |
| **Response:** The current wording of R4 was in part in response to NYISO's earlier comment and the SDT believed they had addressed it. The phrase "establish" was chosen to allow entities to simply republish prior values each year if their inputs have not changed. Changing to your suggested language would require an entity to "prove" their inputs haven't changed. | |

| Organization/Group | Question 2 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| Bonneville Power | BPA does not believe any are incorrect. |
| **Response:** Thank you for your supportive comment. | |
| Ontario IESO | None |
| Hydro One Networks | None |
| NPCC Regional Standards Committee | None |

4. The drafting team has modified the Violation Risk Factors for MOD-008 to reflect industry concerns that they did not reflect NERC's VRF definitions. NERC's VRF definitions are listed below. Are the current VRFs established correctly? If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.

High Risk Requirement:

(a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement:

(a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement: is administrative in nature and

(a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or

(b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

**Summary Consideration:**

The industry opinion as expressed in this request for comments indicates a preference in favor of the current Violation Risk Factors, which are lower. The team once again iterates that it believes that per the current NERC definitions of violation risk factors, no part of this standard (TRM) if not correctly applied would have a direct affect on the state or capability of the bulk power system.

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| Ontario IESO | No | The VRF for R4 should be a Medium. R4 stipulates that the TOP establish a TRM. Given that TRM is |

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| | | that portion of the ATC reserved to cover for uncertainties that can affect transmission reliability, failure to establish this value could result in the TOP facing unreliable operations due to the TSP offering and committing this value as a transmission service to transmission users. The end result could have a direct impact on the control and reliability of the BES. |
| **Response:** The drafting team disagrees. The majority of the team and industry believes that a violation of R4 does not directly affect the electrical state or the capability of the bulk power system. | | |
| FirstEnergy | Yes | FE supports the SDT's adjustment of VRFs such that no VRF within the ATC standards exceeds a "Lower" rating. We concur with the team's reasoning and rationale provided in response to ballot comments in making this change. |
| **Response:** Thank you for your supportive comment. | | |
| PJM | Yes | PJM supports NERC's position to revise all Violation Risk Factors to have an assigned risk factor of "Lower." A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. |
| **Response:** Thank you for your supportive comment. | | |
| ISO RTO Council/Standards Review Committee (SRC) | Yes | The MOD standards assess the correct amount of reliability risk in areas that do not affect reliability. The IRC supports the position that no requirement from this set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. |
| **Response:** Thank you for your supportive comment. | | |
| MRO NERC Standards Review Subcommittee | Yes | The MRO commends the SDT on revising the VRFs to Lower. We believe the revised VRFs are in-line with the NERC definitions of the VRF levels. |
| **Response:** Thank you for your supportive comment. | | |
| SERC ATCWG | Yes | |
| WECC Market Interface Committee / | Yes | |

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| Sub Commtt / ATC Task Force | | |
| Kansas City Power & Light | Yes | |
| WECC Market Interface Committee ATC Task Force | Yes | |
| Manitoba Hydro | Yes | |
| Public Service Commission of South Carolina | Yes | |
| Duke Energy Corporation | Yes | |
| Bonneville Power | Yes | |
| Oncor Electric Delivery | Yes | |
| Pepco Holdings, Inc | | |
| Gainesville Regional Utilities | Yes | |
| Hydro One Networks | Yes | |
| Entergy Services Inc. | Yes | |
| The Midwest ISO | Yes | |
| Southwest Power Pool | Yes | |
| American Transmission Company | Yes | |
| Xcel Energy | Yes | |
| Texas-New Mexico Power company | Yes | |
| Orlando Utilities | Yes | |

| Organization/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| Commission | | |
| New York Independent System Operator | Yes | |
| EPSA | | no comment |

5. The drafting team has modified the Violation Severity Levels for MOD-008 to reflect industry concerns that they were too “pass/fail” oriented. Are the current VSLs established correctly? If “No,” please identify specific VSLs and suggest changes to the language.

**Summary Consideration:**

The industry opinion as expressed in this request for comments indicates a preference in favor of the current Violation Severity Levels. One commenter expressed concern on R2 having only a single VSL of severe. The drafting team believes that if a requirement is a pass/fail, and therefore has only one “VSL” that VSL has to be severe. VSLs refer to how badly a requirement was missed, not to the criticality of that particular requirement. Violation Risk Factors address the criticality of a particular element.

Two other commenters expressed concerns on double jeopardy in the standard, or having a single event result in multiple violations. While this is an issue that has to be addressed by the compliance side of NERC and its policies, the team did review the standards with this concept in mind. As a result of this review the team revised the wording on the VSL’s for Requirement 5 to reinforce that an incorrect value developed under R4, that was properly made available per R5, is not a violation of R5.

| Organization/Group | Question 4: | Question 4 Comments: |
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| PJM | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations — this language to be added to the standard. |
| **Response:** The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.<br><br>VSLs for R2: SDT modified the phrasing to be clear so that if you use CBM (in violation of R2) you aren’t double penalized for also violating the “only the components of…”<br><br>VSLs for R5: The SDT modified all four VSLs to be clear that the accuracy portion refers to the values matching those developed in R4, not the absolute accuracy of the values. This was to make the VSL clearly match the requirement in R5 for transmission of values. This is for a situation where the values are incorrect, but were transmitted. The violation would be of R4, not of R5. | | |
| FirstEnergy | No | The Severe VSL stated for requirement R2 does not seem appropriate if a TOP/TSP included elements of uncertainty that were outside of those items explicitly stated in R1 so long as all of the items in R1 are covered AND that CBM is not included in its TRM. See proposed change above for R2. |
| **Response:** Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements | | |

| Organization/Group | Question 4: | Question 4 Comments: |
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| that do not allow the use of uncertainty other then those in the list. The order also directed that the standard specify that TRM not include elements of CBM. The Violation Risk Factor determines the impact a violation could have on the bulk electric system, the Violation Severity Level is a measure of how badly a requirement was violated. In the case of a pass/fail requirement, the violation severity level is severe. | | |
| ISO RTO Council/Standards Review Committee (SRC) | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but the IRC has a concern regarding the possibility of multiple violations resulting from a single event. The IRC requests that the potential for double counting of violations for a single event be eliminated. |
| **Response:** The SDT has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.<br><br>VSLs for R2: SDT modified the phrasing to be clear so that if you use CBM (in violation of R2) you aren't double penalized for also violating the "only the components of…"<br><br>VSLs for R5: The SDT modified all four of the VSLs to be clear that the accuracy portion refers to the values matching those developed in R4, not the absolute accuracy of the values. This was to make the VSLs clearly match the requirement in R5 for transmission of values. This is for a situation where the values are incorrect, but were transmitted. The violation would be of R4, not of R5. | | |
| SERC ATCWG | Yes | |
| WECC Market Interface Committee / Sub Commtt / ATC Task Force | Yes | |
| Kansas City Power & Light | Yes | |
| WECC Market Interface Committee ATC Task Force | Yes | |
| Manitoba Hydro | Yes | |
| NPCC Regional Standards Committee | Yes | |
| Public Service | Yes | |

| Organization/Group | Question 4: | Question 4 Comments: |
|---|---|---|
| Commission of South Carolina | | |
| Duke Energy Corporation | Yes | |
| Bonneville Power | Yes | |
| Oncor Electric Delivery | Yes | |
| Gainesville Regional Utilities | Yes | |
| MRO NERC Standards Review Subcommittee | Yes | |
| Ontario IESO | Yes | |
| Hydro One Networks | Yes | |
| Entergy Services Inc. | Yes | |
| The Midwest ISO | Yes | |
| American Transmission Company | Yes | |
| Xcel Energy | Yes | |
| Texas-New Mexico Power company | Yes | |
| Orlando Utilities Commission | Yes | |
| EPSA | | no comment |

6. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on MOD-008.**

**Summary Consideration:**

A popular comment under question 5 related to the implementation plan. Because Mod 008 can be implemented independent of the other standards and because Mod 008 being implemented in one area and not another would not cause a coordination problem, the standard team is keeping the current implementation language.

EPSA made some very detailed comments, and the team attempted to respond to all of them. Those responses to EPSA's comments are below in the individual comments.

Many of the other comments and questions posted under question #5 are similar or verbatim repetitions of questions asked under questions 1-4, so their summary will not be repeated here.

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

| Organization/Group | Question 5 Comments: |
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| CenterPoint Energy | The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a single control area. |
| **Response:** This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| EPSA | This comment relates also to the NAESB recommendation that no additional business practices related to TRM will be |

| Organization/Group | Question 5 Comments: |
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| | developed. Our comments are based also on Order 890 Paragraph 207 which states in part: "The purpose of increasing the consistency and transparency of ATC calculations is to reduce the potential for undue discrimination in the provision of transmission service, specifically by reducing the opportunity for transmission providers to exercise excessive discretion. We find that the amount of discretion in the existing ATC calculation methodologies gives transmission providers the ability and opportunity to unduly discriminate against third parties. In order to minimize this discretion, the Final Rule requires that all ATC components (i.e., TTC, ETC, CBM, and TRM) and certain data inputs, data exchange, and assumptions be consistent and that the number of industry-wide ATC calculation formulas be few in number, transparent and produce equivalent results ."EPSA does not believe that the mandate given by FERC to NERC and to NAESB has been carried out. EPSA accepts that in calculating ATC, Transmission operators need a margin, which is deducted from the TTC or AFC as appropriate, to allow for uncertainties in forecast conditions and thus to insure that Transmission Service is not oversold. As it represents an allowance for uncertainties, it is recognized that TRM is based on assumptions about future conditions and is in general, determined probabilistically. However, based on the proposed actions of the two standards development organizations, in order to meet FERC's Order to "increas[e] the consistency and transparency of ATC calculations" and to "reduc[e] the opportunity for transmission providers to exercise excessive discretion" the industry has provided standards that: ? Require Transmission Operators to only identify various elements if they are used in establishing TRM. At no point in the standard however, is any direction provided on how the Transmission Operators determine whether or not to use the various components or, if used, how values are to be established.<br><br>? Make no provision for monitoring or reporting on utilization of TRM? Make no provision for verifying from season to season or year to year whether the values utilized in establishing TRM were or remain appropriate. These standards therefore impose only a minimal requirement for transparency and no requirement for consistency in establishing TRM and no requirement to monitor its usage to verify that assumed values are appropriate. The current NERC and NAESB standards on TRM are reminiscent of the previous NERC standard on ATC which was developed in response to Order 888. It required only that Transmission Operators document their methodology for calculating ATC, much like other fill-in-the-blank standards. Clearly in approving Order 890 and more particularly in Order 693 where they declined to approve other industry fill-in-the-blank standards, FERC has determined that such a standard is insufficient. Yet, with respect to TRM, the industry, through NERC and NAESB, seems prepared to submit standards to FERC that demonstrate that very little progress has been made. |

**Response:** There was a lot of ground covered in this comment, and it is not really possible to break it into sections like some of the other commenter's submittals. The team will attempt to answer the various topics by addressing them individually.

Tracking TRM: Unlike CBM, TRM is not called upon, tracked or reserved nor is it possible to do so. TRM is simply a margin that would, in theory, be sufficient such that reasonable deviations from the system conditions modeled when ATC was calculated would not result in unscheduled operator actions and/or curtailment of transactions. If EPSA has specific recommendation on how to monitor and report the utilization of TRM please file a SAR to modify the standard to include those.

| Organization/Group | Question 5 Comments: |
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| Transparency: The standard requires full transparency among reliability entities. However, NAESB is the appropriate entity to developing any standards related to transparency for market participants.<br><br>Consistency: The standard creates consistency in the way an entity must report, update and describe its TRM. The MOD standards as a group also insure that TRM is applied consistently to all customers. The standard does not establish a consistent (universal) TRM across all regions. Transmission systems vary between regions and even within a region. Applying a universal TRM would, due to the nature of the transmission systems, be detrimental to either reliability, market access, or and more likely both.<br><br>Undue Discrimination: The consistency required by the standard will prevent a utility from undue discrimination since the TRM applies to all users of a path, not just one particular user.<br><br>Overall if the commenter has recommended text for the standard please submit a SAR to further modify the standard. | |
| NERC RTOSDT | The Real Time Operation Standards Drafting Team is concerned that the proposed MOD standards do not include any reference to the Planning and Operating Limits mandated by the current FAC, IRO and TOP standards. These standards already include transmission flow limits both in the longer term planning time frame as well as the shorter term operating time frame. The proposed MOD standards seem to be establishing procedures to calculate the commercial boundaries without a direct link to the required reliability boundaries.<br>MOD-001 R6 states that the TTC "use assumptions" no more limiting than those used in planning. The RTO SDT would ask shouldn't TTCs be required to be "no less limiting" than the SOLs / IROLs computed for the system? Current NERC standards are not just asset limits, they are also system limits. The current standards require that limits be calculated that recognize both local and wide-area impacts. The RTO SDT believes that by at least linking (if not entirely eliminating) the MOD standards to the current SOLs / IROLs requirements, the Industry would be more correctly linking how the system MUST BE operated to any NAESB business practice. Indeed it would seem that current tariffs are based on the computations used in current planning and operating environments. By using the current SOL / IROL limits the procedural / prescriptive requirement in<br>MOD-001 R9 et al would be unnecessary (i.e. they would revert back to the FAC and IRO requirements)The questions for the ATC SDT:? How do these MOD standards relate to the SOLs / IROLs? Why should these ATC/TTC limits be decoupled from the SOLs / IROLs? Shouldn't the long-term SOL / IROL limits computed in Planning be the TTC for the system (or at least the basis for the TTC)? Shouldn't the short-term SOL / IROL be the basis for the ATC for the system?<br>MOD-008 computes margins. By coordinating the MOD standards with the SOL / IROL standards, the only Business (not NERC) requirement may be to define the options on how the TSP could couple the various SOL / IROL values that it obtains from its RCs and TOPs.<br>MOD-028 By using SOLs / IROLs there would be no need to get into ATC / AFC "methodologies". Indeed standards that include "alternatives" are not defining a single "standard approach". But by using specific planning and operating limits the |

| Organization/Group | Question 5 Comments: |
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| | methodologies become irrelevant. The "limit" becomes explicit and well-defined. Any margins or variations about those limits would then be obvious and transparent. What is most important is respecting the reliability-based limits and not how the commercial value is computed. If this idea of using SOLs / IROLs as the limit(s) or at least the basis for those commercial limits, then the TSP becomes a coordinator of which values to use for the commercial periods. The TSP would not be the computer of those limits. Thus MOD-028 could become a business practice for posting ? rather than a standard for computations. |
| **Response:** This comment does not raise any questions related to MOD-008. The SDT agrees that MOD-008 computes margins. Please see the response to this question in the responses to comments for the other MOD standards. | |
| NPCC Regional Standards Committee | The language in the Proposed Effective Date should be modified to be consistent with the other standards |
| **Response:** TRM can be calculated independent of other entities, and therefore, has implementation language that does not require simultaneous implementation across all jurisdictions. | |
| FirstEnergy | FirstEnergy appreciates the Standard Drafting Team's decision to move to a formal comment period based on the prior initial ballot feedback. We commend the team for moving quickly to respond to the ballot comments and providing the industry a revised set of standards to review and comment.<br>**Response:** Thank you for your supportive comment.<br><br>Regarding the revision to the Effective Date, while FirstEnergy agrees that there is a need to ensure that the standard is implemented consistently across the entire continent we are concerned with the Effective Date being subject to approval of ALL regulatory authorities. We believe an appropriate Implementation Plan should reflect a period of time beyond the NERC Board of Trustee approval date that would reflect when the requirements are considered mandatory and enforceable. The timeline should allow sufficient time for regulatory authority reviews, with the intent of sanctions also being enforced in conjunction with the conclusion of the implementation period. However, a delay from a given regulatory agency should not impact when the requirements are considered mandatory and enforceable for the bulk electric system.<br>**Response:** TRM can be calculated independent of other entities, and therefore, has implementation language that does not require simultaneous implementation across all jurisdictions. |
| **Response:** Please see in-line responses. | |
| Duke Energy Corporation | Implementation Plan – Since R2 and M2 link the TRM calculation methodology with the CBM methodology in MOD-004, implementation dates for these standards should be aligned.<br>**Response:** The SDT has modified the measure to address this concern. |

| Organization/Group | Question 5 Comments: |
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| | Since R2 and M2 link the TRM calculation methodology with the CBM methodology in MOD-004, the Standards Drafting Team must avoid creating a duplicate requirement the CBM standard, which could subject entities to multiple penalties for the same violation.<br><br>**Response:** The CBM standard does not have a similar requirement, so there is no potential for multiple penalties for the same violation. |
| **Response:** Please see in-line responses. | |
| Bonneville Power | BPA respectfully submits the following observations and suggestions: a. The sixth component of uncertainty listed in R1.1 should be expanded as follows: - Variations in generation dispatch (including forced or unplanned outages, maintenance outages, and location of future generation)<br>**Response:** Bullet #3 and #6 were modified based on this comment to read<br><br>"Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).<br>"Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation)."<br><br>.b. To comply with FERC Order 890 transparency requirements, R1.5 should not be removed (e.g. " If TRM is not used, a statement of that practice.") – BPA believes a Transmission Operator should be required to provide a robust justification as to why it is not using TRM in it's ATC or AFC calculations.<br>**Response:** The applicability makes this standard apply only to those entities that maintain TRM. At this time the SDT is not requiring an entity to document that they don't use or need TRM.<br><br>c. A new R6 should be added that clearly states the timeframe in which TRM is to be used (i.e. within the hour).<br>**Response:** Unlike CBM, TRM is not called upon, tracked or reserved. TRM is simply a margin that would, in theory, be sufficient that reasonable deviations from the system conditions modeled when ATC was calculated would not result in unscheduled operator actions and/or curtailment of transactions.<br><br>d. The Time Horizons listed for all requirements should include the "Long-term Planning" Horizon, as TRM is to be calculated beyond the seasonal window.<br>**Response:** The use of "Time Horizons" in this standard is in the form of a compliance element, and refers to the manner in which compliance evaluates the implications of a violation of the standard. In this context, time horizon has to do with the |

| Organization/Group | Question 5 Comments: |
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| | urgency of addressing a violation, e.g., how quickly a violation needs to be rectified. Together, the Violation Risk Factor and Time Horizon aid a compliance auditor in determining sanctions. Accordingly, the SDT believes that the appropriate horizon for compliances does not include "Long-term Planning."<br><br>e. Balancing Authorities may be appropriately identified as Applicable Entities in this MOD and request that the Standards Drafting Team provide an explanation as to why they are not listed.<br>**Response:** Only Transmission Operator's are assigned requirements in this standard and therefore they are the only applicable entity. |
| **Response:** See imbedded Responses. | |
| Oncor Electric Delivery | This standard should not apply to ERCOT for the reason expressed in question 2. |
| **Response:** This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| ISO RTO Council/Standards Review Committee (SRC) | Although the SDT had the appropriate Team to establish a default percentage for TRM, the FERC deadline did not allow enough time to complete this portion of the requirement. Since TRM is a reliability margin, the IRC encourages the Team to provide what ever input it currently has in a 'parking lot' for a possible future Team to undertake the development activity. There should be a default percentage to be used without requiring specific documentation, work papers and load flow cases if a straight percentage such as 5% is used. Additional information would be required only if a greater percentage is used. |
| **Response:** The drafting team in numerous discussions examined the use of a fixed percentage rather then specifying the areas on uncertainty. The standard as it is currently written does not require or forbid the use of a fixed percentage as a margin, but does require that the entity explain the rationale for the percentage. Additionally the standard requires that the margin represent only the areas of uncertainty specified in R1 and not include any items included in CBM. We encourage the ISO RTO Council to draft a SAR if further development in TRM is desired. | |
| MRO NERC | 1. The MRO commends the SDT in making significant changes to this standard and reissuing it for comment. The MRO |

| Organization/Group | Question 5 Comments: |
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| Standards Review Subcommittee | believes the eventual standard that is approved will serve the industry and customers better as a result<br>**Response:** Thank you for your supportive comment.<br><br>2. The MRO believes that the first time you use an abbreviation or acronym, you must spell out the full term followed by the abbreviation or acronym in brackets. Subsequent use of the term is then made by its abbreviation or acronym.<br>**Response:** The team agrees that abbreviations or acronyms should generally not be used until defined, but was unable to find an instance of this in the standard. If you are referencing "ATC Path," that is a defined term and therefore not an acronym or abbreviation. |
| **Response:** Please see in-line responses. | |
| Ontario IESO | The language in the Proposed Effective Date should be modified to be consistent with the other standards |
| **Response:** TRM can be calculated independent of other entities, and therefore, has implementation language that does not require simultaneous implementation across all jurisdictions. | |
| Hydro One Networks | Language in the Proposed Effective Date should be modified to be consistent with the other standards, e.g. MOD-001-1 |
| **Response:** TRM can be calculated independent of other entities, and therefore, has implementation language that does not require simultaneous implementation across all jurisdictions. | |
| American Transmission Company | The first time that each abbreviation or acronym is introduced, the full terminology should be stated followed by the abbreviation or acronym in brackets (i.e. ATC).<br>**Response:** The team agrees that abbreviations or acronyms should generally not be used until defined, but was unable to find an instance of this in the standard. If you are referencing "ATC Path," that is a defined term and therefore not an acronym or abbreviation.<br><br>The Proposed Effective Date for MOD-008-1 is different then that written for MOD-001-1. Why the difference in the Effective Date?<br>**Response:** TRM can be calculated independent of other entities, and therefore, has implementation language that does not require simultaneous implementation across all jurisdictions.<br><br>We do not believe that the SDT has to provide a definition of TRMID. Requirement 1 outlines the specifics of TRMID and we find the definition unnecessary. The SDT should explain why this definition is necessary and what if anything is it including that the requirement does not already contain.<br>**Response:** The team believes the definition is helpful, and was asked by a previous commenter to provide a definition. Additionally, the term may be used in NAESB Business Practices. |

<table>
<tr><th>Organization/Group</th><th>Question 5 Comments:</th></tr>
<tr><td>Texas-New Mexico Power company</td><td>This standard should not apply to ERCOT for the reason expressed in question 2.</td></tr>
<tr><td colspan="2">Response: This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>Brazos Electric Power Cooperative, Inc.</td><td>Brazos Electric believes that for a TOP operating in a single-control area region like ERCOT that the establishment of TRM may have no reliability benefits. The Applicability Section 4.1 for MOD-008 as written in this draft states "Transmission Operators that maintain TRM" could possibly be interpreted that this applies only to those TOPs who have a need to establish TRM because of the region it operates in. Otherwise in R1 it is recommended that an "if applicable" clause be inserted to address this issue.</td></tr>
<tr><td colspan="2">Response: This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) “it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) “it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, “An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.” <u>Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.</u> The SDT believes that a regional variance “Based on a justifiable difference between regions or between sub-regions within the Regional geographic area” could be pursued by ERCOT. (Loc. Cit.)</td></tr>
<tr><td>Electric Service Delivery</td><td>These comments are filed on behalf of City of Austin d/b/a Austin Energy to address proposed NERC 5 MOD Standards. Austin Energy is a municipally owned electric utility and a transmission service provider with the Electric Reliability Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with no explicit transmission services being sold. Current ERCOT market rules allow open transmission access to all loads and resources. ERCOT will continue to operate as a</td></tr>
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| Organization/Group | Question 5 Comments: |
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| | Single Balancing Authority under Nodal market design. Accordingly, as explained in more detail below, the NERC 5 MOD Standards should not be applied to ERCOT and transmission service providers within ERCOT under its current or proposed Nodal market design. Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. Applicable definitions: According to NERC Reliability Standards Glossary of Terms, Available Transfer Capability (ATC) is defined as: ?A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability (TTC) less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows? TTC is defined as: the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions. CBM is defined as the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. TRM also is a component of ATC defined as: that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. Comments: ERCOT is an interconnection and a region with no synchronous AC ties with any other interconnections. In July 2001, based on a deregulated Retail and restructured Wholesale Markets, the ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT market is designed such that there are no explicit transmission services being sold, hence, Available Transfer Capability (ATC) is not a measure used in a commercial activity within the ERCOT market. The current ERCOT market rules allow open transmission access to all eligible loads and resources without considering any specific Transmission Service Provider (TSP). Transmission facilities ratings are based upon individual branch element designs and in cases of dynamic ratings, ambient conditions are also considered. ERCOT has several DC ties and an asynchronous tie using a Variable Frequency Transformer (VFT); however, the associated interchange capabilities are planned and coordinated by the TSPs involved. The current ERCOT Zonal Market uses a flow based congestion management methodology to predict potential congestions in the Day Ahead and Adjustment Periods. During the operating period, generation shift factors are used to determine the dispatch needed to remain within the constrained limits. The local congestions are managed using full AC load flow analysis and unit specific redispatch.MOD-001-1 is entirely about methodology and calculation of ATC, therefore, this standard is not applicable to ERCOT.MOD-008-1 covers Transmission Reliability Margin (TRM) methodology calculation. Mathematically, ATC is defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin (CBM). Therefore, TRM also is not applicable to ERCOT.MOD-028-1 covers Area Interchange calculation Methodology. Since ERCOT is a single control area, Area Interchange calculation is not applicable.MOD-029-1 covers Rated System Path Methodology, which is used to calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT.MOD-030-1 covers Flowgate methodology calculation of ATC, and therefore, is not applicable to ERCOT.ERCOT is currently transitioning to a Nodal Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a Security Constrained Economic Dispatch (SCED) approach to dispatch individual generating units and manage congestion. In the Nodal Market, ERCOT will still operate as a |

| Organization/Group | Question 5 Comments: |
|---|---|
| | Single Balancing Authority. This again will not use ATC methodology, and aforementioned standards are not applicable to ERCOT in its ensuing Nodal Market. Therefore, Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. |
| **Response:** **Response:** This standard is intended to apply to all entities that have chosen to maintain a TRM. To the extent ERCOT does not choose to maintain TRM, ERCOT is effectively exempt from this standard.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| Orlando Utilities Commission | Requirements 1, 3, 4 and 5 are great exactly as they are. They are a good balance of standardization, disclosure and recognition that different parts of the transmission system function differently and are most sensitive to different factors.<br>**Response:** Thank you for your supportive comment.<br><br>For Requirement #2, what is the reliability purpose for limiting the items that an entity can consider when establishing TRM?<br>**Response:** Requirement 2 is based on FERC Order 890 instructions to NERC to develop a list of uncertainties for TRM and establish requirements that do not allow the use of uncertainty other then those in the list. The order also directed that the standard specify that TRM not include elements of CBM. |
| **Response:** Please see in-line responses. | |
| Gainesville Regional Utilities | None at this time. |

## Standard Development Roadmap

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## Definitions of Terms Used in Standard

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**ATC Path:** Any Posted Path[1] or any other combination of Point of Receipt and Point of Delivery for which Available Transfer Capability is calculated.

**Available Transfer Capability (ATC):** A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.

**Available Transfer Capability Implementation Document (ATCID):** A document that describes the implementation of a methodology for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC), and provides information related to a Transmission Service Provider's calculation of ATC or AFC.

**Transmission Operator Area:** The collection of Transmission assets over which the Transmission Operator is responsible for operating.

**Existing Transmission Commitments (ETC):** Committed uses of a Transmission Service Provider's Transmission system considered when determining Available Transfer Capability or Available Flowgate Capability.

**Planning Coordinator:** See Planning Authority.

**Postback:** Positive adjustments to Available Transfer Capability or Available Flowgate Capability as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

**Business Practices:** Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices**.**

**Block Dispatch:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

**Dispatch Order:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

**Participation Factors:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

[1] See 18 CFR 37.6(b)(1)

## A. Introduction

1. **Title:** **Available Transmission System Capability**

2. **Number:** **MOD-001-1**

3. **Purpose:** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors.

4. **Applicability:**

   **4.1.** Transmission Service Provider.

   **4.2.** Transmission Operator.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** Each Transmission Operator shall select one ATC methodology[2] for calculating ATC (Area Interchange methodology, Rated System Path methodology) or AFC (Flowgate methodology) for each ATC Path per time period identified in R2 for those Facilities within its Transmission Operator Area. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R2.1.** Hourly values for at least the next 48 hours.

**R2.2.** Daily values for at least the next 31 calendar days.

**R2.3.** Monthly values for at least the next 12 months (months 2-13).

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows including:

**R3.2.1.** How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

**R3.2.2.** A rationale for the defined accounting.

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[2] All ATC Paths do not have to use the same methodology and no particular ATC Path must use the same methodology for all time periods.

**R3.3.** The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating transfer of Flowgate capability.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.

**R3.5.** A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

**R3.6.** A description of how outages are considered in ATC calculations, including:

**R3.6.1.** The criteria used to determine when an outage impacts a daily ATC or AFC calculation.

**R3.6.2.** The criteria used to determine when an outage impacts a monthly ATC or AFC calculation.

**R3.6.3.** How outages (including those outages from other Transmission Service Providers that are unrecognized) are processed.

**R4.** The Transmission Service Provider shall notify the following entities (via electronic mail) before implementing a new or revised ATCID: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

**R4.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

**R4.3.** Each Transmission Operator associated with the Transmission Service Provider's area.

**R4.4.** Each Planning Coordinator adjacent to the Transmission Service Provider's area.

**R4.5.** Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

**R4.6.** Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

**R5.** The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.** When calculating TTC or TFC the Transmission Operator shall use assumptions no more limiting than those used in planning of operations for the corresponding time period studied. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.** When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in planning of operations for the corresponding time period studied. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to 80 hours per calendar year during which calculations are not required to be performed.

**R8.2.** Daily values, once per day.

**R8.3.** Monthly values, once per week.

**R9.** Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below for use in ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations.
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.

- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), and TTC for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

**R9.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

**R9.2.** This data shall be made available by the Transmission Service Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one of the specified methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within its Transmission Operator Area. (R1).

**M2.** The Transmission Service Provider shall provide ATC or AFC values and identification of the selected methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 48 hours of hourly values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly values calculated at all times (Months 2-13). (R2.3)

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** The Transmission Service Provider shall provide evidence (such as dated electronic mail messages) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

**M5.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

**M6.** The Transmission Operator shall provide a copy of the assumptions (such as loop flow, generation re-dispatch, switching operating guides, load shedding or data sources for load forecast and facility outages) used to calculate TTC or TFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC or TFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

**M7.** The Transmission Service Provider shall provide a copy of the assumptions (such as loop flow, generation re-dispatch, switching operating guides, load shedding or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

**M8.** The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly values on at least the minimum frequencies specified in R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R8)

**M9.** The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R9. (R9)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.

The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.

The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.

The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.

The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.

If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Operator did not select one of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission Operator Area. |
| R2. | The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours.<br>**OR**<br>Has calculated daily ATC or AFC values for more than the next 21 calendar days but less than the next 31 calendar days.<br>**OR**<br>Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months. | The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours.<br>**OR**<br>Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days.<br>**OR**<br>Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months. | The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 21 hours.<br>**OR**<br>Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days.<br>**OR**<br>Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months. | The Transmission Service Provider calculated less than 11 hourly ATC or AFC values.<br>**OR**<br>Calculated less than 8 daily ATC or AFC values.<br>**OR**<br>Calculated less than4 monthly ATC or AFC values.<br>**OR**<br>Did not use the selected methodology(ies) to calculate ATC. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>**OR**<br>The Transmission Service Provider has an ATCID, but it does not include two or more of the information items described in R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>**OR**<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include any of the information described in R3. |
| R4. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, but not more than 30 calendar days after, its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation. | The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation. |
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in R4. |
| R6. | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | greater). | Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | |
| R7 | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10%, of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |
| R8. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 80-hour per year requirement.<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>**OR** | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 80-hour per year requirement.<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>**OR** | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 80-hour per year requirement.<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>**OR** | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 80-hour per year requirement.<br>**OR**<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>**OR**<br>For Monthly, the values described in the ATC equation |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. | For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | changed and the Transmission Service provider did not calculate for 28 or more calendar days. |
| R9 | N/A | The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available more than 30 calendar days but less than 45 calendar days after receiving a request. | The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available 45 calendar days or more but less than 60 calendar days after receiving a request. | The Transmission Service Provider did not make the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available for 60 calendar days or more after receiving a request. |

## E. Regional Variances

None.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | April 1, 2005 | Effective Date | New |
| 0 | January 13, 2006 | Fixed numbering from R.5.1.1, R5.1.2., and R5.1.3 to R1.5.1., R1.5.2., and R1.5.3.<br>Changed “website” and “web site” to “Web site.” | Errata |
| 1 | | | Revision |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

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**Business Practices:** Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices**.**

**Block Dispatch:** A ~~simplification~~ set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

**Dispatch Order:** A ~~simplification~~ set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

**Participation Factors:** A ~~simplification~~ set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

[1] See 18 CFR 37.6(b)(1)

## A. Introduction

1. **Title:** **Available ~~Transfer~~ Transmission System Capability**

2. **Number:** **MOD-001-1**

3. **Purpose:** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors.~~To promote the consistent and reliable application and documentation of Available Transfer Capability (ATC) calculations for analysis and system operations.~~

4. **Applicability:**

   **4.1.** Transmission Service Provider.

   **4.2.** Transmission Operator.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities~~, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the set of standards is approved by the NERC Board of Trustees~~.

## B. Requirements

**R1.** Each Transmission Operator shall select one ATC methodology[2] for calculating ATC (Area Interchange methodology, Rated System Path methodology)~~,~~ or AFC (Flowgate methodology) for each ATC Path per time period identified in R2 for ~~use in determining Transfer Capabilities of~~ those Facilities within its Transmission ~~operating~~ Operator ~~area~~Area. ***[****Violation Risk Factor: ~~Medium~~Lower**]** **[***Time Horizon: Operations Planning***]***

**R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the ~~ATC~~ methodology or methodologies selected by its Transmission Operator(s): ***[****Violation Risk Factor: Lower]~~Medium~~**~~]~~** ***[****Time Horizon: Operations Planning***]***

**R2.1.** Hourly ~~ATC~~ values for at least the next ~~168~~ 48 hours.

**R2.2.** Daily ~~ATC~~ values for at least the next 31 calendar days.

**R2.3.** Monthly ~~ATC~~ values for at least the next 12 months (months 2-13).

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: ***[****Violation Risk Factor: Lower***]*** ***[****Time Horizon: Operations Planning***]***

**R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows including:

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[2] All ATC Paths do not have to use the same ~~ATC~~ m~~M~~ethodology and no particular ATC Path must use the same ~~ATC~~ m~~M~~ethodology for all time periods.

**R3.2.1.** How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

**R3.2.2.** A rationale for the defined accounting.

**R3.3.** The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ~~ATC~~transfer of Flowgate capability.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.

~~**R3.5.**The identity of the Transmission Service Providers from which it receives data for use in calculating transfer capability.~~

~~**R3.6.**~~**R3.5.** A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate ~~Transfer~~ transfer ~~Capability~~ or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate ~~Transfer~~ transfer ~~Capabilities~~ or Flowgate capabilities among multiple owners or users of a~~ single~~n ~~path~~ ATC Path or Flowgate.
- Processes used to allocate ~~AFC~~ transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

~~**R3.7.**~~**R3.6.** A description of how outages ~~durations~~ are considered in ATC calculations, including:

~~**R3.7.1.**~~**R3.6.1.** The criteria used to determine when an outage impacts a daily ATC or AFC calculation.

~~**R3.7.2.**~~**R3.6.2.** The criteria used to determine when an outage impacts a monthly ATC or AFC calculation.

**R3.6.3.** How outages (including those outages from other Transmission Service Providers that are unrecognized) are processed.

**R4.** The Transmission Service Provider shall notify the following entities (via electronic mail) before implementing a new or revised ATCID: ***[****Violation Risk Factor: Lower****]*** ***[****Time Horizon: Operations Planning****]***

**R4.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

**R4.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

**R4.3.** Each Transmission Operator associated with the Transmission Service Provider's area.

**R4.4.** Each Planning Coordinator adjacent to the Transmission Service Provider's area.

**R4.5.** Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

**R4.6.** Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

**R5.** The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.** When calculating TTC~~, AFC and ATC,~~ or TFC the Transmission Operator ~~and Transmission Service Provider~~ shall ~~each~~ use assumptions ~~consistent with~~no more limiting than those used in planning of operations for the corresponding ~~in any associated operations studies or planning studies for the~~ time period studied. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.** When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in planning of operations for the corresponding time period studied. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**~~R7.~~R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: ***[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]***

**~~R7.1.~~R8.1.** ~~For h~~Hourly ~~ATC~~values, once per hour. Transmission Service Providers are allowed up to 80 hours per calendar year during which calculations are not required to be performed.

**~~R7.2.~~R8.2.** ~~For d~~Daily ~~ATC~~values, once per day.

**~~R7.3.~~R8.3.** ~~For m~~Monthly ~~ATC~~values, once ~~a~~ per week.

**~~R8.~~R9.** Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below for use in ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in ~~R8~~R9.1 and ~~R8~~R9.2: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- ~~Confirmed f~~Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations.
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.

- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), and TTC for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

**~~R8.1.~~R9.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

**~~R8.2.~~R9.2.** This data shall be made available by the Transmission Service Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one ~~or more~~ of the specified ~~ATC~~ methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within ~~the~~ its Transmission Operator~~'s operating area~~Area. (R1).

**M2.** The Transmission Service Provider shall provide ATC or AFC values and identification of the selected ~~ATC~~ methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least ~~168~~ 48 hours of hourly ~~ATC~~ values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily ~~ATC~~ values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly ~~ATC~~ values calculated at all times (Months 2-13). (R2.3)

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** The Transmission Service Provider shall provide evidence (such as dated electronic mail messages) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

**M5.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

**M6.** The ~~Transmission Service Provider and~~ Transmission Operator shall ~~each~~ provide a copy of the assumptions (such as loop flow, generation re-dispatch, switching operating guides, load shedding or data sources for load forecast and facility outages) used to calculate TTC~~, ATC and AFC~~ or TFC as well as other evidence (such as copies of operations ~~and~~ planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC~~, ATC, and AFC~~ or TFC are no more limiting than those ~~were consistent with those~~ used in planning of operations ~~or planning studies~~ for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

**M7.** The Transmission Service Provider shall provide a copy of the assumptions (such as loop flow, generation re-dispatch, switching operating guides, load shedding or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

**~~M7~~M8.** The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly ~~ATC~~ values on at least the minimum frequencies specified in ~~R7~~ R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (~~R7~~R8)

**~~M8~~M9.** The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with ~~R8~~R9. (~~R8~~R9)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

-The Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.

-The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.

-The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.

-The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.

-The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.

-If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

-The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| **R1.** | **N/A** | **N/A** | **N/A** | **The Transmission Operator did not select one ~~or more~~ of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission** Operator Area**.** |
| **R2.** | **The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours.<br>OR<br>Has calculated daily ATC or AFC values for more than the next 21 calendar days but less than the next 31 calendar days.<br>OR<br>Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months.~~N/A~~** | **The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours.<br>OR<br>Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days.<br>OR<br>Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months.~~N/A~~** | **The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 21 hours.<br>OR<br>Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days.<br>OR<br>Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months.~~N/A~~** | **The Transmission Service Provider calculated less than 11 hourly ATC or AFC values.<br>OR<br>Calculated less than 8 daily ATC or AFC values.<br>OR<br>Calculated less than4 monthly ATC or AFC values.<br>OR<br>Did not use the selected methodology(ies) to calculate ATC.~~The Transmission Service Provider did not calculate ATCs based on the time periods in R2.~~<br>~~OR~~<br>~~Did not use the selected methodology(ies) to calculate~~** |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | ~~ATC.~~ |
| R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>OR<br>The Transmission Service Provider has an ATCID, but it does not include two or more of the information items described in R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>OR<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include any of the information described in R3. |
| R4. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, ~~more than 14,~~ but not more than 30~~,~~ calendar days after, its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation. | The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation. |
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in ~~R5~~R4. |
| R6. | The Transmission Operator determined TTC or TFC using assumptions more | The Transmission Operator determined TTC or TFC using assumptions more | The Transmission Operator determined TTC or TFC using assumptions more | The Transmission Operator determined TTC or TFC using assumptions more |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| | limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater).~~N/A~~ | limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater).~~N/A~~ | limiting than those used in planning of operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater).~~N/A~~ | limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater).~~The Transmission Service Provider or Transmission Operator did not determine ATC using assumptions consistent with those used in planning or operations studies for the studied time period.~~ |
| R7 | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10%, of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R7~~R8. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more ~~than 12~~ hours but not more than 15 hours, and was in excess of the 80-hour per year requirement~~,~~. <br><br>OR<br><br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more ~~than 2~~ calendar days but not more than 3 calendar days.~~,~~<br><br>OR<br><br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for ~~8~~ seven or more calendar days, but less than 14 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 80-hour per year requirement.~~,~~<br><br>OR<br><br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days~~,~~.<br><br>OR<br><br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 80-hour per year requirement~~,~~.<br><br>OR<br><br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days~~,~~.<br><br>OR<br><br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 80-hour per year requirement~~,~~.<br><br>OR<br><br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days~~,~~.<br><br>OR<br><br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days. |

| R # | Lower VSL | Moderate | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R8~~R9 | N/A | The Transmission Service Provider made the requested data items specified in ~~R8~~ R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in ~~R8~~R9, available more than 30 calendar days but less than 45 calendar days after receiving a request. | The Transmission Service Provider made the requested data items specified in ~~R8~~ R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in ~~R8~~R9, available 45 calendar days or more but less than 60 calendar days after receiving a request. | The Transmission Service Provider did not make the requested data items specified in ~~R8~~ R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in ~~R8~~R9, available for 60 calendar days or more after receiving a request. |

## E. Regional Variances

None.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | April 1, 2005 | Effective Date | New |
| 0 | January 13, 2006 | Fixed numbering from R.5.1.1, R5.1.2., and R5.1.3 to R1.5.1., R1.5.2., and R1.5.3.<br>Changed “website” and “web site” to “Web site.” | Errata |
| 1 | | | Revision |

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

## Implementation Plan for Standard MOD-001-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-001-1 — Available Transfer Capability which requires the selection of an ATC methodology and describes the parts of the ATC process that apply to all entities, regardless of methodology chosen.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### Retired Standards

This standard supersedes the current MOD-001-0.

FAC-012-1 — Transfer Capability Methodology includes four requirements. MOD-001-1 incorporates the requirements from FAC-012-1 as follows:

- R1 (Documentation of the Transfer Capability Methodology).
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (Responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

FAC-013-1 — Establish and Communicate Transfer Capabilities, includes two requirements. MOD-001-1 incorporates the two requirements from FAC-013-1 as follows:

- R1 (Calculation of the Transfer Capabilities).
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-001-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

### Implementation Plan for Standard MOD-001-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-001-1 — Available Transfer Capability which requires the selection of an ATC methodology and describes the parts of the ATC process that apply to all entities, regardless of methodology chosen.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## ~~Modified~~ Retired Standards

This standard supersedes the current MOD-001-0.

FAC-012-1 — Transfer Capability Methodology includes four requirements. ~~This standard~~ MOD-001-1 incorporates the ~~four~~ requirements from FAC-012-1 as follows:

- R1 (Documentation of the Transfer Capability Methodology).
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (Responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

FAC-013-1 — Establish and Communicate Transfer Capabilities, includes two requirements. MOD-001-1~~This standard~~ incorporates the two requirements from FAC-013-1 as follows:

- R1 (Calculation of the Transfer Capabilities).
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-~~012~~013-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-001-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities~~, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date MOD-001, MOD-028, MOD-029, and MOD-030 are approved by the NERC Board of Trustees.~~ . This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

Please **DO NOT** use this form to submit comments on the current draft of MOD-001. Comments must be submitted by **May 15, 2008.**

If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-452-8060.

**Background Information MOD-001 — Available Transmission System Capability.** (An "umbrella" standard requires the selection of a methodology, the updating of values, and the sharing of procedures and data – formerly called, "Available Transfer Capability.")

An initial ballot of MOD-001-1 — Available Transmission System Capability, was conducted March 3-12, 2008 and there were several suggestions for modifying the standard that were submitted with ballots. The drafting team withdrew the standard from the ballot process, and made several changes to the standard based on stakeholder comments, including the following:

1. The title and purpose were modified to more clearly reflect the reliability aspects of 'why' ATC and AFC are calculated.
2. The standard was modified to be clear that MOD-001 does not require conversion of AFC to ATC. While the OASIS Requirements require that ATC be posted, the Drafting Team could not find any reason that AFC must be converted to ATC for reliability. MOD-030 continues to provide the equation to convert AFC to ATC, that shall be used 'when' the conversion occurs, but the NERC standards do not define 'when' that conversion must occur. The standard now uses the phrase "ATC or AFC", where applicable. While the use of 'or' is not typically used in standards, since any Transmission Service Provider is only required to calculated either AFC or ATC, based on method that was selected, the use of 'or' is appropriate.
3. Several definitions were modified to provide greater clarity.
4. Several VRFs were changed from "Medium" to "Lower" in response to industry comments. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
5. R2 was changed such that only 48 Hourly values are required instead of 168 Hourly values. It is necessary for reliability to know the hourly information for the next 1-2 days. However, while OASIS posting is required for 168 hours, the Drafting Team does not see any reliability benefit to calculating more than 48 hours of Hourly data. Daily and monthly values provide the necessary reliability information for time periods more than 48 hours in the future.
6. R6 (and R7) were modified to clarify that assumptions need to be "no more limiting" rather than "consistent" with those used in planning or operations for the

corresponding time period. In addition, the existing R6 was split to clarify which aspects the Transmission Operator and Transmission Service Provider are responsible for. Measures were expanded to be more clear.

7. A more graded approach was applied to the VSLs where appropriate.

8. The Transmission Service Provider was given an 80-hour-per-year grace period in R8 for scheduled or unscheduled outages of any ATC calculation software that impact the hourly calculation.

**Please review the revised version of MOD-001 and then answer the following questions. You do not have to answer all questions. Enter All Comments in Simple Text Format.**

1. **The drafting team modified several definitions in MOD-001 based on stakeholder comments. Do you agree with the revised definitions? If not, please specify any definition that you disagree with and, if possible, provide a suggested revision.**

   ☐ Yes – definitions are acceptable as revised

   ☐ No – one or more definitions needs revision – see comments

   Comments:

2. **MOD-001-1, R1 says, "Each Transmission Operator shall select one methodology for calculating the available capability on the bulk electric system…" The Drafting Team believes that the Transmission Operator is the appropriate entity since the Transmission Operator is ultimately responsible for operating a reliable system while using all Transmission Service Providers' calculated available capability. However, some parties have commented that the Transmission Service Provider should select the methodology for calculating the available capability since (a) a Transmission Service Provider may use the transmission of multiple Transmission Operators, (b) there are 'registered' Transmission Operators that do not calculate ATC, and (c) the Transmission Operator has only 2 responsibilities -- R1 to pick a calculation method, and R6 where the Transmission Operator must calculate consistent with planning studies.**

   **Should the Transmission Operator or the Transmission Service Provider select the methodology for calculating the available capability on the bulk electric system?**

   ☐ Transmission Operator

   ☐ Transmission Service Provider

   ☐ No preference

3. **The drafting team modified some requirements and associated measures in MOD-001 to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct.**

   Incorrect Requirement(s) or Measure(s):

4. **The drafting team has modified the Violation Risk Factors for MOD-001 to reflect industry concerns that they did not reflect NERC's VRF definitions. NERC's VRF definitions are listed below:**

   **High Risk Requirement**:
   (a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could

place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or
(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

**Medium Risk Requirement**:
(a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or
(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

**Lower Risk Requirement**: is administrative in nature and
(a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or
(b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

**Are the current VRFs established correctly?**

☐ Yes
☐ No

**If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.**

Comments:

5. **The drafting team has modified the Violation Severity Levels for MOD-001 to reflect industry concerns that they were too "pass/fail" oriented and to reflect the modifications to the requirements and measures. Are the current VSLs established correctly?**

☐ Yes
☐ No

**If "No," please identify specific VSLs and suggest changes to the language.**
Comments:

6. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-001.**

   Comments:

| | Individual or group. | Name | Organization | Group Name | Lead Contact | Question 1 | Question 1 Comments | Question 2 | Question 3 | Question 4 | Question 4 Comments | Question 5 | Question 5 Comments | Question 6 Comments |
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| | Individual | | | American Public Power Association | Allen Mosher | No - one or more definitions needs revision - see comments | “Counterflows” should be a defined term. It is used in MOD-1, MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-28-1 R10, for example, reads: “counterflowsF are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.” This definition does not in any way describe what a counterflow is. “Postbacks” should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: “PostbacksF are changes to firm [non-firm] ATC [AFC] due to a change in the amount of Firm [non-firm] Transmission Service reserved or scheduled for a period, as defined in Business Practices. Postbacks are generally a positive | Transmission Service Provider | R3.3 - seems awkward for tranfer capability to not be a defined term when TTC and ATC are defined; at minimum, edit to read transfer or Flowgate capability. R3.6 - clarify that "outages" are transmission outages, generator outages or both. R8.1 - why hardwire 80 hours per calendar year during which calculations are not required to be performed? Should this be a compliance Measure? | Yes | | Yes | | Excellent work - my thanks to the SDT members. |

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| | | | | | | quantity." Also, capitalize existing transmission commitments in the definition of ATC. | | | | | | | |
| Individual | Paul Rocha | CenterPoint Energy | | | | | | | | | | | The group of standards is for ATC and TRM methodologies that are not used in ERCO that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these not add value to the ERCOT region and could increase congestion in the region. Acc previously submitted comments to these standards asking for an exemption for the standards unacceptable unless the following provision is added to each standard: Th or any other region that operates as a single control area. |
| Group | | | SERC Available Transfer Capability Working Group (ATCWG) | Dough Bailey | Yes - definitions are acceptable as revised | | No Preference | | Yes | | | | |
| Individual | John Harmon | The Midwest ISO | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | R3.3 – last line should read: … calculating ATC or AFC. R3.4 – last line should read: … calculating ATC or AFC. R3.5 – Each bullet should read: … allocate ATC or AFC… R6 and R7 – The term 'assumptions' is not specific enough for entities to prepare for compliance. The Midwest ISO requests the standard to list specific assumptions within the scope and what defines 'more limiting' for each of them. For example, is load assumption within the scope? If yes, what load assumption is more limiting? If it is not possible, the Midwest ISO believes that this topic from Order 890 should be left out from any standard and left to FERC to address issues on a case by case basis. R9 – Please expand/clarify the intentions of the 4th bullet. What specific aggregated firm capacity is being referenced? Capacity in ETC for each flowgate as specified by reservations? An example would be very beneficial. R9 – The 13th bullet should read: .. (TRM), and TTC or TFC for all….. M6 – Include reference for TFC, should read: … used for TTC, or TFC, and Operations Planning…. | Yes | | No | The VSLs for R8 of MOD-001 are inconsistent to the VSLs stated for R10 of MOD-030 although each is related to comparable requirements regarding the frequency of recalculations. If the suggestion of deletion of R10 in MOD-030 is accepted the inconsistency will be addressed. Otherwise, the team should align these VSLs consistently. | |
| Individual | John Dalessi | Transmission Agency of Northern California | | | Yes - definitions are acceptable as revised | | No Preference | | Yes | | Yes | | R.9 lists many data elements that another entity can request and a TSP is obligated this data themselves, and R.9 should be clarified to state that the TSP is not obigate Perhaps this is implied in R9.1, but if so it should be stated more clearly. Also the fir assume the requested data is for use in the requestor's ATC or AFC calculations, but used in the ATC/AFC calcualation of the TSP receiving the request. |
| | | | | | | | | MOD-01, R9. Could the NERC Team please clarify "which" Load | | | | | |

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| | Group | | | WECC Market Interface Committee / Sub Commtt / ATC Task Force | W. Shannon Black | Yes - definitions are acceptable as revised | | Transmission Service Provider | Forecast it is requesting? Hourly? Daily? For what affected area? MOD-01, R9. Could the NERC Team please clarify that Block/Dispatch Order and Participation Factors do not call for the submission of specific schedules; rather, these defintions only call for dispatch rules from which approximations can be made. | Yes | | Yes | | |
| | Group | | | Southwest Power Pool | Kevin Bates | Yes - definitions are acceptable as revised | | | | Yes | | | | R3.6.3. How outages (including those outages from other Transmission Service Prov<br>processed. Define "unrecognized." Does this also refer to outages that are not used<br>outside the TSP's model and therefore do not impact calculations?<br>______________________________________________________________<br>R9. Within thirty calendar days of receiving a request by any Transmission Service P<br>Reliability Coordinator, or Transmission Operator for data from the list below for use<br>Transmission Service Provider receiving said request shall begin to make the reques<br>subject to the conditions specified in R9.1 and R9.2: The concern of R9 is numerous<br>unnecessary burden for TSPs fulfilling said requests. SPP feels a justification should l<br>comunication between requestor and TSP so desired result is obtained. |
| | Individual | Maria Neufeld | Manitoba Hydro | | | Yes - definitions are acceptable as revised | | No Preference | | Yes | | Yes | | |
| | Individual | Jack Cashin/Barry Green | EPSA | | | Yes - definitions are acceptable as revised | | No Preference | R6/7. I believe the wording of this requirement in the previous draft was superior. In the revised language, deletion of the word "consistent" allows for discontinuities in the ATC calculations. For example, if the assumptions used in "planning of operations" in the period beyond one month are different than for those in the current month, this could create discontinuities where the calculations adopt different assumptions. In addition, the current language has broken the explicit link between planning studies and operations studies. | | no comment | | NO COMMENT | We offer two additional comments. First, with respect to the purpose of this standar<br>previous draft was more appropriate. The previous draft stated that consistency in tl<br>documentation were part of the purpose of this standard. We believe those are impo<br>included. Secondly, requirement 3.2 dealing with counterflows is insufficient in the c<br>consistency in the use of counterflows on all interfaces would not be appropriate. Inc<br>single system, it is likely appropriate that the counterflows on some interfaces be tre<br>historical usage of the interface. However, to create a standard that requires only an<br>and a statement of the rationale, with no guidance on appropriate methodologies or<br>sufficiently enforceable and amounts to a fill-in-the-blank standard. |
| | Group | | | Public Service Commission of South Carolina | Phil Riley | Yes - definitions are acceptable as revised | | No Preference | | Yes | | Yes | | |
| | | | | | | | | | Requirement 2 •While the IRC understands that the SDT believes that the requirements need to address the amount of ATC or AFC data calculated and the frequency of calculation associated with them, these requirements should be business practices and should be considered NAESB scope and | | | | | |

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| | Group | | | ISO RTO Council/Standards Review Committee (SRC) | Charles Young | Yes - definitions are acceptable as revised | | | eliminated from the MOD Standards. The MODs can still address FERC orders and be reliability based without the MOD-001 R2 (amount of ATC or AFC) and R8 (frequency ATC recalculation) and MOD-030 R10 (frequency AFC recalculation) requirements. The violation severity levels for these draft standards now have a graded implementation. The possibility of multiple violations resulting from a single event still remains. The IRC requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. This language should be added to the standard as a new item 6 to section A of MOD-001. Requirement 3 •R3.2.1 - The IRC understands the SDT's reasons for using "Confirmed" reservations in accordance with the FERC regulations. However, reservations that are in "Accepted", as well as, "Confirmed" status should be included. Once service is "Accepted" by a TSP it cannot be retracted. Using reservations that are in "Accepted" and "Confirmed" status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TSP from decrementing for accepted and confirmed TSRs. We understand that some TSPs maintain two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TSPs who maintain two sets of ATC values to post the "internal" ATC values to provide greater transparency and | Yes | The MOD standards assess the correct amount of reliability risk in areas that do not affect reliability. The IRC supports the position that no requirement from this set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of | No | ERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but the IRC has a concern regarding the possibility of multiple violations resulting from a single event. The IRC requests that double counting of violations for a single event be eliminated. The IRC recommends that the SDT add a new item 6 to section A of MOD-001 that states "A single event shall not result in multiple violations". A review of MOD-001 R2 and R8 should be performed for determination of multiple violations resulting from one event. | The IRC applauds the efforts of the NERC Standards Drafting Team (SDT) in providir comment that include many of the Industry's comments from the Ballot. However, tl require modification. The MOD standards extend into areas that should be covered a Practices (as defined in MOD-001 Definitions). The frequency of postings and freque be NAESB Business Practices, and not included in the NERC Standards as reliability t details for MOD-001 R2 and R7). Non-firm should be removed from this reliability st |

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| | | | | | | | | | give customers a more accurate picture of capability available to new requests. •R3.6 - For R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD 1 and applied consistently across MODS 28, 29 and 30. Requirement 8 •If R8 is not moved to NAESB Business Practices then revise R8.1 and the VSL to align the requirement and NAESB practice which allows OASIS to be down 2% of the time over a year. Modify the 80 hour per year allowable outage requirement to 175 hours per year (8760 hrs/year x 0.02= 175 hours). This VSL does not become a possible sanction until the accumulated amount of hours missed exceeds 175 hours. The 175 hours is for planned, system IT outages. Unplanned, system IT outages should not be included in this total. | | the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. | | | |
| | | | | | | | | | Requirement 1: I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall select one ATC methodology for calculating ATC (Area Interchange methodology, Rated System Path methodology)or AFC (Flow gate methodology) for each ATC Path per time period identified in R2 for those facilities within its Transmission Service Provider area." Comment: The TOP is to operate its transmission operating area in a reliable manner and ensure SOLs are determined. ATC is a transmission service market concept, not a reliability function. In areas where there is a transmission service market in operation, there is some reliability | | | | | |

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| | Individual | H. Steven Myers | ERCOT ISO | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | value to having a representative ATC in play to ensure proper planning is conducted, but reliability is ensured by adherance to the SOLs of the system, not by adherance to ATC. Requirement 3: I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information:" Requirement 4: I suggest modifying the requirement to state: "The Transmission Service Provider with ATC Path(s) shall notify the following entities (via electronic mail) before implementing a new or revised ATCID." Requirement 5: I suggest modifying the requirement to state: "The Transmission Service Provider with ATC Path(s) shall make available the current ATCID to all of the entities specified in R4." Requirement 6: I suggest modifying the requirement to state: "When calculating TTC or TFC, the Transmission Service Provider with ATC Path(s) shall use assumptions no more limiting than the estimated SOLs used in planning of operations for the corresponding time period studied." Requirement 7: I suggest modifying the requirement to read: "When calculating ATC or AFC, the Transmission Service Provider with ATC Path(s) shall use assumptions no more limiting than the estimated SOLs used in planning of operations for the corresponding time period studied." Requirement 8: I suggest modifying the requirement to state: "Within 30 calendar days of receiving a request by any Transmission | | | | | I suggest modifying the Applicability section to state: 4.1 Transmission Service Provi Transmission Oerator with ATC Path(s) Comment: It is unclear how failing to meet tl grid reliability. This should be a commercial standard or a business practice rather th Severity Levels: Violation of timeing requirements should not constitute a severe vio failure to attempt to perform the task at all. A high violation could be a long failure t NO attempted corrective action. All other failures in timing should be lower violation |

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| | | | | | | | | | Service Provider, Planning Coordinator, or Reliability Coordinator for data from the list below for use in ATC or AFC calculations, each Transmission Service Provider with ATC Path(s) receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2." Requirement 9.1: I suggest modifying the sub-requirement to state: "The Transmission Service Provider with ATC Path(s) shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months in the future (subject to confidentiality and security requirements)." Requirement 9.2: I suggest modifying the sub-requirement to state: "This data shall be made available by the Transmission Service Provider with ATC Path(s) on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requestor and the provider)." | | | | | |
| | Individual | Aaron Staley | Orlando Utilities Commission | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | | Yes | | Yes | | Overall Question: As written currently, the standard appears to set requirements for<br>but does not require an entity to perform the calculation. For example, R1 and R6 ap<br>TOP doesn't calculate ATC/AFC/TTC/TFC then nothing in the requirements seems to<br>seems to be true of the requirements that apply to a TSP. Is this a correct reading o<br>If the drafting team changes the responsible entity in Requirement 1, will they also<br>What if there is not "planning of operations" activity for the corresponding time peri<br>have an ATC study done, it may not have a corresponding "planning of operations"<br>you provide some examples of what you mean by "assumptions". Requirement 6 &<br>these requirements, specifically what is the reliability purpose of setting a maximum<br>assumption can be? |
| | Group | | | WECC Market Interface Committee ATC Task Force | W. Shannon Black | Yes - definitions are acceptable as revised | | Transmission Service Provider | Mod-001, R9. Could the NERC Team please clarify "which" Load Forecast it is requesting? Hourly? Daily? For what affected area? MOD-001, R9. Could the NERC Team please clarify that Block/Dispatch Order and Participation Factors do not call for the submission of specific schedules; rather, these definitions only call for dispatch rules from which approximations can | Yes | | Yes | | |

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| | | | | | | | | | be made. | | | | | |
| | Individual | Patrick Brown | PJM | | | Yes - definitions are acceptable as revised | | Transmission Operator | Requirement 2 • While PJM understands that the SDT believes that the requirements need to address the amount of ATC or AFC data calculated and the frequency of calculation associated with them, these requirements should be business practices and should be considered NAESB scope and eliminated from the MOD Standards. The MODs can still address FERC orders and be reliability based without the MOD-001 R2 (amount of ATC or AFC) and R8 (frequency ATC recalculation) and MOD-030 R10 (frequency AFC recalculation) requirements. The violation severity levels for these draft standards now have a graded implementation. The possibility of multiple violations resulting from a single event still remains. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. This language should be added to the standard as a new item 6 to section A of MOD-001. Requirement 3 • R3.2.1 - PJM understands the SDT's reasons for using "Confirmed" reservations in accordance with the FERC regulations. However, reservations that are in "Accepted", as well as, "Confirmed" status should be included. Once service is "Accepted" by a TSP it cannot be retracted. Using reservations that are in "Accepted" and "Confirmed" status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TP from decrementing for accepted and confirmed TSRs. We understand that some TPs maintain | Yes | PJM supports NERC's position to revise all Violation Risk Factors to have an assigned risk factor of "Lower." A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations –this language to be | Depth of the ATC MOD standards extends beyond the scope of the reliability standar areas that should be covered and addressed by NAESB Business Practices (as define frequency of postings and frequency of AFC/ATC calculations should be NAESB Busin NERC Standards as reliability based requirements (see specific details for MOD-001 I Specific Comments sections below). Non-firm should be removed from this reliability |

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| | | | | | | | | | two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TPs who maintain two sets of ATC values to post the “internal” ATC values to provide greater transparency and give customers a more accurate picture of capability available to new requests. • R3.6 - For R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD 1 and applied consistently across MODS 28, 29 and 30. Requirement 8 • If R8 is not moved to NAESB Business Practices then revise R8.1 and the VSL to align the requirement and NAESB practice which allows OASIS to be down 2% of the time over a year. Modify the 80 hour per year allowable outage requirement to 175 hours per year (8760 hrs/year x 0.02= 175 hours). This VSL does not become a possible sanction until the accumulated amount of hours missed exceeds 175 hours. The 175 hours is for planned, system IT outages. Unplanned, system IT outages should not be included in this total. | | power system, or the ability to effectively monitor and control the bulk power system. | | added to the standard. Add a new item 6 to section A of MOD-001. For example a review of MOD-001 R2 and R8 and MOD-30 R10 should be performed for determination of multiple violations resulting from one event. | |
| | | | | | | | | | | | | | | These comments are filed on behalf of City of Austin d/b/a Austin Energy to address Austin Energy is a municipally owned electric utility and a transmission service provi Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with being sold. Current ERCOT market rules allow open transmission access to all loads operate as a Single Balancing Authority under Nodal market design. Accordingly, as NERC 5 MOD Standards should not be applied to ERCOT and transmission service pr current or proposed Nodal market design. Austin Energy requests that the NERC Sta to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1 applicable to regions with a Single Balancing Authority that do not use ATC methodo their market operations. Applicable definitions: According to NERC Reliability Standa Transfer Capability (ATC) is defined as: “A measure of the transfer capability remain network for further commercial activity over and above already committed uses. It i (TTC) less existing transmission commitments (including retail customer service), le less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows”. TT power that can be transferred over the interconnected transmission network in a reli specific set of defined pre- and post-contingency system conditions. CBM is defined transfer capability reserved by load serving entities to ensure access to generation f generation reliability requirements. TRM also is a component of ATC defined as: that capability necessary to ensure that the interconnected transmission network is secu uncertainties in system conditions. Comments: ERCOT is an interconnection and a r |

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| | Group | | | Electric Service Delivery | Reza Ebrahimian | | | | | | | | | with any other interconnections. In July 2001, based on a deregulated Retail and res<br>ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT ma<br>no explicit transmission services being sold, hence, Available Transfer Capability (AT<br>commercial activity within the ERCOT market. The current ERCOT market rules allow<br>eligible loads and resources without considering any specific Transmission Service Pr<br>ratings are based upon individual branch element designs and in cases of dynamic ra<br>considered. ERCOT has several DC ties and an asynchronous tie using a Variable Fre<br>the associated interchange capabilities are planned and coordinated by the TSPs invo<br>Market uses a flow based congestion management methodology to predict potential<br>Adjustment Periods. During the operating period, generation shift factors are used to<br>remain within the constrained limits. The local congestions are managed using full A<br>redispatch. MOD-001-1 is entirely about methodology and calculation of ATC, therefo<br>ERCOT. MOD-008-1 covers Transmission Reliability Margin (TRM) methodology calcu<br>defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin<br>applicable to ERCOT. MOD-028-1 covers Area Interchange calculation Methodology.<br>Area Interchange calculation is not applicable. MOD-029-1 covers Rated System Path<br>calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT<br>methodology calculation of ATC, and therefore, is not applicable to ERCOT. ERCOT is<br>Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a S<br>Dispatch (SCED) approach to dispatch individual generating units and manage conge<br>will still operate as a Single Balancing Authority. This again will not use ATC method<br>are not applicable to ERCOT in its ensuing Nodal Market. Therefore, Austin Energy re<br>Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008<br>MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority<br>and any of its components in their market operations. |
| | Individual | Frank Cumpton | California ISO | | | Yes - definitions are acceptable as revised | Please see comments given ion last question. | | | | | | | Purpose – The MOD 1 Purpose as presently written does not clearly relate the intent<br>Purpose statement should be more explicit, i.e. "To require that ATC calculations are<br>and HA) and forecasted system operating conditions on ATC Paths", using one or mo<br>embodied in MOD 28 – 30. Purpose should clearly state "for ATC Paths", and then cl<br>MOD 1 CFR definition of "ATC Path" is very open to interpretation, given that "ATC P<br>Path" via a footnote reference to 18 CFR 37.6(b)(1) OR "any OTHER combination of<br>calculated". Posted Path implies a requirement to post the ATC to an OASIS site, and<br>referenced path. The MOD 1 "ATC" definition does refer to the intention that ATC is c<br>activity". Presumption is that the ATC is posted for sale. ATC Path Definition – Clarify<br>applicable ONLY to interties and internal paths between systems where Transmission<br>activity). Clarify if ANY posting requirement is embodied in these standards. Explana<br>interpretation is that under MOD 1 and 29, the ISO will be required to calculate and<br>The ISO will use the MOD 29 Rated System Path Methodology to calculate ATCs DA,<br>timeframes, consistent with practice in the WECC for interchange ratings. However,<br>based Integrated forward Market under its new MRTU Market design to be implemen<br>will use an Integrated Forward Market in combination with an Full Network Model an<br>imports and exports, procure AS and Balancing energy for RT, to optimize use of the<br>flowgates in the 3000 node FNM. However, the ISO will only be posting ATCs for tran<br>consistent with our Market design and interpretation of the definition of ATC Path, pr<br>standards. Note; The CAISO operates the combined transmission assets of 11 TOs lo<br>one Transmission system for Market purposes. Is this interpretation consistent with<br>believe that MOD 30 contains any requirement to convert the IFM's use of flow gates<br>not related to ATC Paths, as defined by MOD 1? This would appear to be very imprac<br>benefit, as the power flow solution used to dispatch energy in the IFM is only known<br>flow solution is reached for each of the thousands of interconnected transmission ele<br>nodal bus network. R2 & R8 – Should the actual ATC Calculation timing requirements<br>Standard??? Any requirement to calculate and post ATC with any accuracy, should b<br>perhaps weekly values. The requirement to calculate Monthly and yearly ATC values<br>requirements and beyond any reasonable expectation of knowledge of operating con<br>CAISO Market construct. Posting of ATC for timeframes beyond seven days would se<br>knowing what the operationally constraints would be to any degree of accuracy (I.e.<br>planned generation and transmission outages, planned maintenance work). R9 - Doe<br>CAISO release our power flow model to our TO's, absent a NDA??? See 9th bullet. |
| | Group | | | NERC RTOSDT | Jim Case, Chair | | | | | | | | | The Real Time Operation Standards Drafting Team is concerned that the proposed M<br>reference to the Planning and Operating Limits mandated by the current FAC, IRO ar<br>already include transmission flow limits both in the longer term planning time frame<br>time frame. The proposed MOD standards seem to be establishing procedures to calc<br>without a direct link to the required reliability boundaries.<br>==================================================<br>that the TTC "use assumptions" no more limiting than those used in planning. The R<br>required to be "no less limiting" than the SOLs / IROLs computed for the system? Cu<br>asset limits, they are also system limits. The current standards require that limits be<br>and wide-area impacts. The RTO SDT believes that by at least linking (if not entirely<br>the current SOLs / IROLs requirements, the Industry would be more correctly linking<br>to any NAESB business practice. Indeed it would seem that current tariffs are based<br>planning and operating environments. By using the current SOL / IROL limits the pro<br>MOD-001 R9 et al would be unnecessary (i.e. they would revert back to the FAC and<br>the ATC SDT: • How do these MOD standards relate to the SOLs / IROLs • Why shou<br>from the SOLs / IROLs • Shouldn't the long-term SOL / IROL limits computed in Plan<br>least the basis for the TTC) • Shouldn't the short-term SOL / IROL be the basis for th<br>computes margins. By coordinating the MOD standards with the SOL / IROL standard<br>requirement may be to define the options on how the TSP could couple the various S<br>its RCs and TOPs. MOD-028 By using SOLs / IROLs there would be no need to get in<br>Indeed standards that include "alternatives" are not defining a single "standard appr<br>and operating limits the methodologies become irrelevant. The "limit" becomes expli<br>variations about those limits would then be obvious and transparent. What is most in<br>based limits and not how the commercial value is computed. If this idea of using SO<br>the basis for those commercial limits, then the TSP becomes a coordinator of which<br>periods. The TSP would not be the computer of those limits. Thus MOD-028 could be<br>– rather then a standard for computations. |

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| | Group | | | NPCC Regional Standards Committee | Guy V. Zito | Yes - definitions are acceptable as revised | | Transmission Service Provider | NPCC Participating Members have the following comments on specific requirements 1. R3.6.3: This subrequirement is too vague and its addition is not necessary. Subrequirements R3.6.1 and R3.6.2 suffice to hold the TSP responsible for considering the impact of outages in ATC calculation. How the outages are processed has no bearing on the ultimate scenarios (topologies) that the TSP must consider. 2. Also we do not agree with the changes made to R6 and R7. By “no more limiting than” the assumptions used in planning of operations for the same time period, it would imply that the TOP and TSP may use less restrictive (or more liberal) assumptions. The results could be that the TTCs and ATCs are higher than the planned operational parameters, giving rise to potential unreliability. We do not see a problem with the previous wording of “consistent with”, and this should be reinstated | Yes | | No | NPCC Participating Members have the following comments on the VSL: 1. R3: There is a potential overlap between High and Severe. For an ATCID does not include “two or more” of the information items in R3, it could mean does not include all of the information items. This is the same condition as a Severe. We suggest to reword the High VSL to “does not include up to 2 of the information items in R3”; and the Severe VSL to “or its ATCID does not include 3 or more of the information described in R3”, or numbers along that line. 2. We do not agree with the VSLs for R6 and R7 for reasons noted under Q3, above. | NPCC Participating Members do not see the role of TOP in this standard. The TOP’s p<br>transmission operating area in a reliable manner, and determine SOLs and where ne<br>capabilities and flowgate capabilities (where applicable). Given the established SOLs<br>the TOP for operational planning, and the TTCs and TFCs determined by other entitie<br>wider area and for different time frames, the TSP needs only to calculate ATCs (or A<br>constraints. In doing so, it should be able to select an ATC calculation method to sui<br>due consideration to the basis of the TTCs and TFCs that affect its service area. With<br>response to Q2, above, that the TSP be the one who selects the ATC method and R1<br>also that it should not be assumed that the TOP area and the TSP area are the same<br>TFCs that affect the TSP’s area may differ from one part to another. Also we believe<br>the method to be used in calculating available transmission transfer capability since<br>processing transmission services, not the TOP. In determining ATCs, the TSP needs<br>determined by the TOPs, RCs, TPs and PCs. Keeping the determination of TTCs (TFC<br>ATC, including the latter’s methodology, would be the appropriate approach in movir<br>standards. |
| | | | | | | | | | R1- The selection of a calculation methodology should reside with the party responsible for calculating ATC. As stated in question 2, FE believes that R1, the selection of an ATC methodology, should be applicable to the Transmission Service Provider (TSP) and not the Transmission Operator since within many RTO areas it is the TSP who maintains the ATC methodology documentation and performs the ATC calculations. This is the case in a large portion of the continent and a standard should not be written in a way that would knowingly require an assignment delegation for a large number of potential responsible entities. Assigning the requirement | | | | | |

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| | Group | | | FirstEnergy | Doug Hohlbaugh | Yes - definitions are acceptable as revised | | Transmission Service Provider | responsibility to the TSP would also work for non-market areas of the continent where a TO/TOP also serves as its own its own TSP. The TOP should provide a support role in providing data and information that is needed by the TSP to fulfill its responsibilities in calculating ATC. The TSP is overseeing transmission service requests and making determination of the viability of such requests. The TOP has ultimate reliability responsibility in the real-time environment and will manage its system to its system operating limits regardless of the ATC methodology used by its TSP to approve transactions that make use of the transmission operator's system. R3.3 – There appears to be a typo. Replace "of" in the words "transfer of Flowgate capability" with "or" R3.3, R3.4, R3.5 – Suggest the SDT consider replacing the words "transfer or Flowgate capability" with "ATC or AFC" to improve readability. R3.6 – Replace "ATC" with "ATC or AFC". R3.6 (sub-requirements) - The sub-requirements of R3.6 require that outages be included in the daily and monthly calculations, but excludes hourly calculation periods. In MOD-030 (AFC Methodology) requirement R5.2 requires expected transmission and generation outages are included for all applicable time period calculated. It is suggested that a single requirement reside in MOD-001 to cover the hourly, daily and monthly aspects for this intent that would assure consistent application across the MOD-028, MOD-029 and MOD-030 standards. R8 – It is not clear why the frequency for recalculation is only | Yes | FE supports the SDT's adjustment of VRFs such that no VRF within the ATC standards exceeds a "Lower" rating. We concur with the team's reasoning and rationale provided in response to ballot comments in making this change. | No | The VSLs for R8 of MOD-001 are inconsistent to the VSLs stated for R10 of MOD-030 although each are related to comparable requirements regarding the frequency of recalculations. If the above suggestion revising MOD-001 R8 and deletion of R10 in MOD-030 is accepted the inconsistency will be addressed. Otherwise, the team should align these VSLs consistently. | FirstEnergy appreciates the Standard Drafting Team's decision to move to a formal c initial ballot feedback. We commend the team for moving quickly to respond to the b industry a revised set of standards to review and comment. Regarding the revision t FirstEnergy agrees that there is a need to ensure that the standard is implemented c continent we are concerned with the Effective Date being subject to approval of ALL appropriate Implementation Plan should reflect a period of time beyond the NERC Bo would reflect when the requirements are considered mandatory and enforceable. The for regulatory authority reviews, with the intent of sanctions also being enforced in c implementation period. However, a delay from a given regulatory agency should not considered mandatory and enforceable for the bulk electric system. |

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| | | | | | | | | | focused on ATC, and does not read "ATC or AFC", similar to the wording used for calculating in R2. In MOD-030 R10 addresses recalculation for the AFC but it seems that with the suggested change in R8 of MOD-001, that R10 of MOD-030 could be eliminated. Additionally they are inconsistent in that R10 does not provide for the 80 hour annual allowance that is stated in R8. | | | | | |
| | Individual | Thad Ness | AEP | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | | | | | | The Applicability of this Standard should be solely upon the TSP, the Transmission O Standard. From the previous set of responses, it is the apparent belief of the SDT th for reliability (response to AECI for example). We disagree. Considering that ATC is a forecasted system conditions (load, outages, generation dispatch, others' transactio margins (TRM and CBM of own entity and other systems), using the calculated ATC t transmission reliability would be – at best – unwise. Transmission Reliability can be a individual Facility loadings and/or other parameters, for example. The calculation of exactly for the purpose stated in the definition of ATC: "A measure of ... capability.... note the definition does not infer ATC is a measure of reliability. Granted, ATC is cal values and concepts (such as ratings, contingency analysis aspects, SOLs etc), BUT assessment of transmission reliability – and therefore not a function for the Transmi Transmission Service Provider. |
| | Group | | | PPL Supply Group | Annette Bannon | | | | R4. PPL suggests that Purchasing/Selling Entities should be included in the listing of entities under Requirement R4 who have access to the ATCID. R8. PPL suggests that the following changes be made to the calculation time periods: R8.1 should require hourly ATC to be calculated "as close to continuously as possible". Once per hour is too slow. R8.2 should require daily ATC to be calculated at 15 minute or less intervals. Once per day is too slow. R8.3 should require that Monthly ATC be calculated hourly or at most daily. Once per week is too slow. | | | | | PPL suggests that the standard should require that the TSP make available the new |
| | Individual | Greg Rowland | Duke Energy Corporation | | | No - one or more definitions needs revision - see comments | ATC path : Insert the phrase "or Available Flowgate Capability" after the phrase "Available Transfer | Transmission Operator | R8.1 – The following sentence, "Transmission Service Providers are allowed up to 80 hours per calendar year during which calculations are not required to be performed." appears somewhat capricious and should be clarified to show the drafting team's intentions. As presented, it would permit a TP to decide not to calculate hourly ATC for a 3 1/3 day period. Also, R8 does not require | Yes | | Yes | | |

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| | | | | | | | Capability". | | recalculation if none of the calculated values identified in the ATC equation have changed. Does R8.1 limit the exemption provided in R8 to 80 hours per year? M7 - insert the phrase “list of contingencies,” before the phrase “loop flow”. | | | | | |
| | Individual | Greg Ward / Darryl Curtis | Oncor Electric Delivery | | | No - one or more definitions needs revision - see comments | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). | No Preference | | Yes | | Yes | | This standard should not apply to ERCOT for the reason expressed in question 1. |
| | Group | | | Bonneville Power Administration | Denise Koehn | Yes - definitions are acceptable as revised | | Transmission Operator | BPA does not believe any are incorrect. | Yes | | Yes | | BPA thanks the drafting team for the modifying MOD-001 to not require the conversi your assessment that there is no reliability need for such conversion. Additionally, BI observations and suggestions: a. The purpose statement of MOD-001 be modified as 890-A: Purpose: To ensure the consistent and transparent application and document used in the calculation of Available Transfer Capability (ATC) or Available Flowgate C listed for all requirements should include the “Long-term Planning” Horizon, as ATC c seasonal window. c. Balancing Authorities may be appropriately identified as Applica request that the Standards Drafting Team provide an explanation as to why they are |
| | Individual | Alice Druffel | Xcel Energy | | | Yes - definitions are acceptable as revised | | | 1) R3.6.3 Need to strike "that are unrecognized". The term "unrecognized" is problematic and vague. 2) R3.2.2 Please clarify what you mean by "defined accounting". 3) R3.3 | Yes | | Yes | | We feel that the applicability of this standard as proposed is problematic. We also dc is resolved by choosing either the TOP or TSP. While it is not a perfect solution, we f applicability to remain at the regional level. We suggest the following wording: "Regi its members". |

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| | | | | | | | | | There is a typo. Please change "of" to "or". | | | | | |
| | Individual | Earl Fair | Gainesville Regional Utilities | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | R1: In reading the standard and the definitions, it seems that the std. doesn"t require an entity to calculate TTC/TFC/AFC, but only tells them how it must be done if it is to be done at all. Am I understanding this requirement correctly? R6: If the responsible entity is changed in R1, with it also be changed in this requirement as well? R6&7: If for example a study for month 10 may not have a corresponding "planning of operations" activity, what action is required to fulfill this requriement? R6&7: What is meant by " assumptions"? Can the team provide some GOOD examples? R6&7: I do not see a reliability purpose of these 2 requirements. I do not see how setting a maximum threshold on limiting assumptions can support a reliability interest. | Yes | | Yes | | None at this time. |
| | Individual | Richard Kafka | Pepco Holdings, Inc. | | | | | Transmission Operator | PHI supports the comments of PJM and will not duplicate the submission of comments | | | | | |
| | | | | | | | | | 1. The MRO agrees with the changes made to replace "ATC" with "ATC or AFC" in the standards. However, the MRO believes this change should be made to R3.6 should be revised this way as well to say "A description of how outages are considered in ATC or AFC calculations, including:". 2. The MRO continues to believe that R4 should be revised to match M4 "The Transmission Service Provider shall provide evidence (such as dated electronic mail messages) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)" The MRO does not see the reliability need to specify the | | | | | |

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| | Group | | | MRO NERC Standards Review Subcommittee | Tom Mielnik | No - one or more definitions needs revision - see comments | The MRO supports the changes to the definitions. However, the MRO believes there is a need to define "counterflows". The MRO suggests that the SDT consider the following definition for Counterflows: "Counterflows are net impacts on a path or flowgate as determined by the Transmission Service Provider and specified in the appropriate implementation document." Capitalize "Existing Transmission Commitments" in the Available Transfer capability definition, since it is a defined term. | Transmission Service Provider | media via how the Transmission Service Provider notifies the following entities. However, if the issue is that the SDT believes that there must be a record of the notification, the MRO suggests that the words "in writing" be used allowing the Transmission Service Provider to determine the media of notification. 3. The MRO believes that R8 should also be revised to refer to "ATC or AFC" rather than just "ATC". 4. The MRO believes that R5 should be revised to delete the words "all of". The phrase "all of" seems to be unnecessary and may result in over-the-top auditing. 5. The MRO believes that the changes made to R6 are a significant improvement to the standard and commends the SDT on taking this more reasonable approach to consistency, that is "no more limiting than those used in planning of operations." 6. The MRO believes that R9 should be revised to delete the words "any" from "Within thirty calendar days of receiving a request by any Transmission Service Provider...". R9 should be revised to delete the words "all" from "Unit commitments and order of dispatch, to include all designated network resources...". R9 should be revised to delete the words "Any" from the phrase "Any firm and non-firm adjustments...". R9 should be revised to delete the words "Any" from the phrase "Any other services that that impact .....". R9 should be revised to delete the word "all" from "Values of CBM and TRM and TTC for all ATC [paths or Flowgates." R9 should be revised to delete "any" from the phrase "any Flowgates considered by the Transmission Service | Yes | The MRO commends the SDT in the changes made to VRFs to Lower. The MRO agrees that these changes puts the VRFs more in line with the NERC's definitions of the VRF levels. | Yes | | 1. The MRO commends the SDT in making significant changes to this standard and r believes the eventual standard that is approved will serve the industry and customer believes that the first time you use an abbreviation or acronym, you must spell out t abbreviation or acronym in brackets. Subsequent use of the term is then made by its Transmission Operator shall select one Available Transfer Capability (ATC) methodol Interchange methodology, Rated System Path methodology) or Available Flowgate C methodology) for each ATC Path per time period identified in R2 for those Facilities w Area." R3.3 – last line should read: ...calculating ATC or AFC. R3.4 – last line should – Each bullet should read: ...allocate ATC or AFC... R6 and R7 – Overall, both require MRO asks that the standards drafting team specify what assumptions are referenced Also the MRO objects the requirement to use assumptions that are no more limiting result in potentionally onorous calcualations to determine assumtions that meet this requirements are covered by FERC order #890 anyway. R9 – Please expand/clarify t specific aggregated firm capacity is being referenced? Capacity in ETC for each flowg example would be very beneficial. R9 – The 13th bullet should read: "Values of Capa Transmission Reliability Margin (TRM),and TTC for all ATC Paths or (TFC) for Flowgat should read: "Alternatively the Transmission Operator may demonstrate that the sar TTC or TFC..." |

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| | | | | | | | | | Provider receiving the request..." R9 should be revised to delete the word "all" from the phrase "Values of TTC and ATC for all ATC Paths for those...". These uses of "any" and "all" seem to be unnecessary and may result in over-the-top auditing. 7. The MRO believes comparable changes should be made to deleting "all" and "any" in the Measures, the Compliance section, and the Violations Severity Levels to match the changes to R9. 8. R3.6.3 Need to strike "that are unrecognized". The term "unrecognized" is problematic and vague. 9. R3.2.2 Alternate language for the statement "a rationale for the defined accounting" A suggestion to use counterflow process instead. 10. R3.3 There is a typo. Please change "of" to "or". | | | | | |
| | | | | | | | | | R3.3 - Replace "--- transfer of Flowgate capability." by "--- transfer or Flowgate capability." R3.6.3 - Entergy is not sure what the parenthetical is implying, specifically the phrase, "that are unrecognized." In addition, Entergy proposes that rather than processing of outages, it should refer to modeling of outages in ATC calculations, therfore, replace "processed" by "modeled". R6 and R7 - The phrase "planning of operations" may be better understood if the term "reliability" was inserted at the beginning. We assume that the SDT is trying to tie the reliability planning studies/activities to the ATC calculations. Similar terms are used in MOD-030. (This also raises the question of why it is in MOD-030 and not MOD-028 and MOD-029.) If all instances can use the same phrase, we think the standards would benefit from the standardization. R8.1 needs to be | | | | | |

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| | Group | | | Entergy Services Inc | Narinder K. Saini | Yes - definitions are acceptable as revised | Revised definitions are acceptable | Transmission Operator | worded as requirement rather than giving allowance/exemption from the requirement for 80 hours (approx 1% of 8760 hours) in a calendar year. Entergy recommends the language "Hourly values, once per hour at least 99% of hours every calendar year." R9 - This requirement is for sharing the data by TSP with others who need it for calculation of their ATCs. This requirement is not to replace the requirement of Order 889 37.6(b)(2)(ii) "On request, the Responsible Party must make all data used to calculate ATC and TTC for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (e.g., thermal, voltage, stability)) in electronic form within one week of the posting. The information is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material." If it can be emphasized this fact, it will greatly clarify some confusion that some stakeholders are having regarding data sharing. | Yes | | Yes | | The effective date info provided in the standards posted indicate that all 5 standards seems that MOD-004 should also be a part of the set becoming effective. CBM is refe R3.2.2.2 The term "accounting" implies bookkeeping and dollars - obviously not som reliability standard. We suggest adding some clarification to this requirement to ensu audiences: "A rationale stating how counterflows are accounted for." R3.3 Change "c do not feel that it is prudent to use switching operating guides and load shedding, et even suggest these in M7 seems misguided and in conflict with the current draft of t a grace period similar to R8.1 to account for unforeseen system emergencies where technology issues. |
| | Individual | Ron Falsetti | Ontario IESO | | | Yes - definitions are | | Transmission Service | We have the following comments on specific requirements: 1. R3.6.3: This subrequirement is too vague and its addition is not necessary. Subrequirements R3.6.1 and R3.6.2 suffice to hold the TSP responsible for considering the impact of outages in ATC calculation. How the outages are processed has no bearing on the ultimate scenarios (topologies) that the TSP must consider. 2. We do not agree with the changes made to R6 and R7. | Yes | | No | We have the following comments on the VSL: 1. R3: There is a potential overlap between High and Severe. For an ATCID does not include “two or more” of the information items in R3, it could mean does not include all of the information items. This is the same condition as a Severe. We | We do not see the role of TOP in this standard. The TOP’s primary responsibility is to area in a reliable manner, and determine SOLs and where necessary, transmission tr capabilities (where applicable). Given the established SOLs, TTCs, TFCs that are dete planning, and the TTCs and TFCs determined by other entities such as the RCs, TPs a different time frames, the TSP needs only to calculate ATCs (or AFCs) respecting the |

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| | | | | | | acceptable as revised | | Provider | By “no more limiting than” the assumptions used in planning of operations for the same time period, it would imply that the TOP and TSP may use less restrictive (or more liberal) assumptions. The results could be that the TTCs and ATCs are higher than the planned operational parameters, giving rise to potential unreliability. We do not see a problem with the previous wording of “consistent with”, and this should be reinstated. | | | | suggest to reword the High VSL to “does not include up to 2 of the information items in R3”; and the Severe VSL to “or its ATCID does not include 3 or more of the information described in R3”, or numbers along that line. 2. We do not agree with the VSLs for R6 and R7 for reasons noted above. | so, it should be able to select an ATC calculation method to suit its business model a the basis of the TTCs and TFCs that affect its service area. With this in mind, we sug that the TSP be the one who selects the ATC method and R1 should be revised accor be assumed that the TOP area and the TSP area are the same and hence the basis o TSP's area may differ from one part to another. |
| | Individual | Alessia Dawes | Hydro One Networks | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | There are 2 methodologies listed in R1. Are these the only two from which we have to choose? We suggest rewording the requirement to avoid this confusion by inserting the words "for example". In R6 and R7, we prefer the previous wording "consistent with" instead of "no more limiting" as the new wording may result in the use of less restrictive assumptions and hence give rise to potential unreliability. | Yes | | No | For the severe VSL for R2 keep consistent the wording as per the other levels. The Lower, Moderate, and High VSLs for R4 are missing the words "did not". | In requirement 8, if the 80 days grace period is to account for software outages ther else entities may interpret the requirement as applicable to outages other then softw |
| | | | | | | | | | Modification to Requirement 1: Each Transmission Operator shall select a methodology for calculating ATC or AFC for each ATC Path or Flowgate for each time period identified in Requirements 2.1 - 2.3 for those Facilities within its Transmission Operators Area. Modifications to 2.2 Daily values for at least the next 31 calendar days (Following the 48 Hours specified in R2.1) Modification to 2.3 Monthly values for at least the next 12 months (Following the 31 Calendar days specified in R2.2) Modification to R3: Each TSP shall prepare and keep current an ATCID that includes the following information. (The Phrase "at a minimum" is unnecessary because the TSP | | | | | |

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| | Individual | Jason Shaver | American Transmission Company | | | No - one or more definitions needs revision - see comments | Capitalize "Existing Transmission Commitments" in the Available Transfer capability definition, since it is a defined term. We do not believe that the SDT has to provide a definition of ATCID. Requirement 3 outlines the specifics of ATCID and we find the definition unnecessary. The SDT should explain why this definition is necessary. | Transmission Operator | must comply with the sub-requirements. Any additional information is beyond the requirements and therefore not subject to NERC's audit.) Starting in Requirement 3.3 the phrase "transfer or Flowgate capability" is used. Does this phase equate to ATC and AFC where ATC is equal to transfer capability and AFC is equal to Flowgate capability? We would prefer that the SDT remain consistent and use the phrase "ATC or AFC if the phrases are equal. In Requirement 3.3 did the SDT mean "transfer or Flowgate capability" or "transfer of Flowgate capability"? The requirement currently uses the "of" word. In order to maintain a consistent use of the phrase "ATC or AFC" we suggest the following change to Requirement 3.6. "A description of how outages are considered in ATC or AFC calculations including:" The SDT should explain any disagreement with our suggested modification. R5 should be revised to delete the words "all of" to avoid being overly inclusive. R6 should be revised to "no more limiting than those used in the planning of operations." Modifications to R8: The TSP shall recalculate ATC or AFC on the following frequency, unless none of the calculated values identified in the ATC or AFC equations have changed. Question to R8.1: How will the 80 hours per calendar year be calculated? (Does a non-calculation period that is exempt in Requirement 8 count to the 80 hours?) R9 should be revised to eliminate "any" and "all" to avoid being overly inclusive: (1) delete the words "any" from "Within thirty calendar days of receiving a request by any | Yes | | Yes | | The first time that each abbreviation or acronym is introduced, the full terminology s abbreviation or acronym in brackets (i.e. ATC, AFC, TTC, and TFC). The SDT should what would be the proposed effective data of this standard. FERC has justification ov operators of the BPS and following their approval the standard would become "enfor even in the US these standards will not become "enforceable" until all regulatory aut have approved this set of standards? If this is the case how would NERC insure such |

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| | | | | | | | | | Transmission Service Provider..."; (2) delete the words "all" from "Unit commitments and order of dispatch, to include all designated network resources..."; (3) delete the words "Any" from the phrase "Any firm and non-firm adjustments..."; (4) delete the words "Any" from the phrase "Any other services that that impact ....."; (5) delete the word "all" from "Values of CBM and TRM and TTC for all ATC [paths or Flowgates."; (6) delete "any" from the phrase "any Flowgates considered by the Transmission Service Provider receiving the request..."; (7) delete the word "all" from the phrase "Values of TTC and ATC for all ATC Paths for those...". 5. Delete "all" and "any" in the Measures, the Compliance section, and the Violations Severity Levels to avoid being overly inclusive. | | | | | |
| | Individual | Rex McDaniel | Texas-New Mexico Power Company | | | No - one or more definitions needs revision - see comments | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company (TNMP) is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market | No Preference | | Yes | | Yes | | This standard should not apply to ERCOT for the reason expressed in question 1. |

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| | | | | | | | and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). | | | | | | | |
| | Individual | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | | | No - one or more definitions needs revision - see comments | For the ERCOT region/market the concept of ATC, AFC are not applicable. It is suggested that the definition of ATC have some consideration for whether there is a required "commercial activity" for it in a region. | Transmission Operator | | | | | | As commented in Question #1, Brazos Electric does not believe that the application would serve any reliability need or commercial market purpose. Therefore an exclusi requirements based on whether a TO/TOP operates soley in a single control area reg |
| | | | | | | | The NYISO has continuing concerns with two of the revised definitions: (i) "ATC Path;" and (ii) "ATC." ATC Path: The NYISO previously expressed concern with the SDT's use of a new defined term "ATC Path" instead of the term "Posted Path" that was used in earlier versions of MOD-001 and is more consistent with the terminology used in FERC's OASIS posting regulations. The NYISO continues to be concerned that the proposed definition of "ATC Path" set forth in the latest version of proposed MOD-001 could, absent revision or clarification, subject the NYISO to potential penalties that would be inappropriate given the nature of its financial reservation system and the inapplicability | | | | | | | |

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| | | | | | | | of certain OASIS posting requirements to it. Specifically, as the NYISO has explained in previous comments, ATC serves a fundamentally different purpose and is calculated differently in New York, because there are no express physical transmission reservations and all desired uses of the grid are accommodated to the extent that customers are willing to pay congestion. FERC has expressly recognized that the NYISO's ATC postings are merely advisory projections that may be of some commercial benefit to customers but that they do not determine whether customers can obtain transmission service. The NYISO has also explained that there are no "Posted Paths" as that term is defined under FERC's OASIS regulations internal to the NYISO and that the NYISO is not required, both because of that fact, and because of FERC orders exempting the NYISO from certain OASIS regulations, to post ATC on its internal interfaces for periods further out than one day-ahead. The current draft of MOD-001 would define "ATC Path" as including both "Posted Paths" and "any other combination of Point of Receipt and Point of | | | | | | | | |

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| | | | | | | | Delivery for which Available Transfer Capability is calculated." The NYISO remains concerned that without clarification this definition could be interpreted in a way that would require the NYISO to post ATC for time periods further out than one day ahead when it is not required by FERC's regulations to make such postings and where such postings would serve no reliability purpose (because they have nothing to do with scheduling or "over-scheduling" long-term transactions.) Given the nature of the NYISO's financial reservation system, and the central role that the output of its day-ahead and real-time market software plays in its ATC calculations (see below), the NYISO would not have any meaningful information to post for periods further out than one day-ahead in any case. The NYISO therefore respectfully requests that the SDT either: (i) remove the defined term "ATC Path" and return to the use of "Posted Path" as that term is defined in FERC's OASIS regulations; or (ii) revise the term "ATC Path" as follows: "ATC Path: Any Posted Path or any other combination of | | The NYISO continues to agree with the ISO/RTO Council that the MOD standards extend into areas that should be covered and addressed by NAESB Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices, and not included in the NERC standards as reliability based requirements Nevertheless, to the extent that the SDT decides to keep such requirements in proposed MOD-001, the NYISO offers the following additional comments or R2, R8, and M2. R2 This requirement continues to reflect an assumption that all Transmission Service Providers are required under FERC's regulations to calculate and post ATC values for periods 48 hours, one month, and one year into the future. This is not true of the NYISO. Because of the nature of its financial reservation system, FERC has only required the NYISO to calculate and post ATCs for its internal interfaces for a period one day-ahead. The NYISO does not post and calculate, and given the nature of its system, cannot post and calculate, ATCs further out than one day ahead for those internal interfaces or for certain controllable lines that link the NYISO to neighboring Transmission Service Providers. Thus, as drafted, R2 would conflict with FERC orders and FERC approved tariff provisions excusing the NYISO from posting longer range ATCs. It would also require the NYISO to calculate and post ATCs that it cannot practically calculate given the nature of its system (under which ATC is determined primarily | | | | | |

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| | Individual | Rick Gonzales | New York Independent System Operator | | | No - one or more definitions needs revision - see comments | Point of Receipt and Point of Delivery for which Available Transfer Capability is calculated, provided, however, that interfaces or paths for which a Transmission Service Provider is not required under FERC's regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead shall not be considered to be ATC Paths" The NYISO's proposed revision would apply to few Transmission Service Providers, and thus would not undermine the proposed requirements or harm reliability. It would, however, be a very important accommodation to the NYISO that would prevent it from being subjected to inappropriate penalties under R1, R2, or R8. Available Transfer Capability ("ATC"): The proposed new definition of "ATC" does not appear to be flexible enough to accommodate the fundamentally different nature of ATC under the NYISO's FERC-approved financial reservation transmission model. As the NYISO has previously explained, a customer's ability to schedule transactions in the NYISO system is not limited by a pre-defined amount of ATC. In New York | Transmission Service Provider | by the output of the NYISO's day-ahead and real-time market software). If R2 is not modified, the NYISO would have to seek a modification (or waiver) from FERC to avoid being subject to penalties for non-compliance with a requirement that should not apply to it. The NYISO respectfully requests that the SDT address the problem by revising proposed R2 as follows: "Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the ATC methodology or methodologies selected by its Transmission Operator(s), except to the extent that the Transmission Service Provider is not required, under FERC's regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] R2.1. Hourly ATC values for at least the next 48 hours. R2.2. Daily ATC values for at least the next 31 calendar days. R2.3. Monthly ATC values for at least the next 12 months (months 2-13). In addition, the violation severity levels for these draft standards now have a graded implementation. Nevertheless, it may still be possible for multiple violations to result from a single unintended event. The NYISO requests that double counting of violations for a single event be eliminated by adding a new Item 6 to Section A of the proposed standard to establish this point. R8 The NYISO has previously asked the SDT to clarify or revise R8 so that Transmission Service Providers such as the NYISO that are not required to post monthly ATC values for internal interfaces (See the | Yes | | No | The NYISO agrees with the ISO/RTO Council comments on this issue. NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now for the most part have a graded implementation, but the NYISO remains concerned regarding the possibility of multiple violations resulting from a single event. Therefore, the NYISO requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. |

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| | | | | | | | ATC is not, in the SDT's words, "a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses." Instead, ATC postings are really "advisory projections" calculated after the NYISO markets close, and transactions are scheduled, based on calculations performed by the NYISO's day-ahead and real-time market software. The fact that a posted ATC is zero does not mean that further commercial activity is precluded because the NYISO may redispatch its system to support additional transactions. A posted ATC value of zero simply indicates that there is congestion at a particular NYISO interface. FERC has granted the NYISO a number of waivers from its OASIS regulations that reflect these differences and has recognized that ATC is merely an "advisory projection" in New York. The NYISO therefore respectfully requests that the SDT accommodate the different nature of ATC under the NYISO's FERC-approved financial | NYISO's response to Question One, above) would not be subject to a requirement to recalculate such values on a weekly basis. Otherwise, R8 would effectively require the NYISO to conduct calculations that FERC has excused it from conducting and that would serve no reliability purpose under the NYISO's financial reservation transmission model. The NYISO therefore respectfully requests that the SDT revise R8 to to clearly establish that Transmission Service Providers need not recalculate ATC values that they are not required to calculate or post under FERC's regulations, or as a result of FERC orders M2 Consistent with the NYISO's comments on R2 and R8, and with past NYISO comments, NERC should revise M2 to clearly state that Transmission Service Providers need not provide evidence that they calculated ATCs that they are not required to calculate or post under FERC's regulations, or as a result of FERC orders | | | | | |

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| | | | | | | | transmission model by either: (i) deleting the proposed definition of ATC; or (ii) specifying that each Transmission Service Provider must include its definition of ATC in its ATCID (and expressly allowing entities such as the NYISO to have definitions that vary from the standard definition); or (iii) revising the definition as follows: "Available Transfer Capability (ATC): A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows, except with respect to Transmission Service Providers that employ FERC-approved financial reservation transmission models in which ATC serves as an advisory projection of potential transmission congestion." Again, the NYISO's proposed revision would not apply to | | | | | | | |

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| | | | | | | | many Transmission Service Providers, and thus would not undermine the proposed standard or harm reliability. It would, however, be a very important accommodation to the NYISO that would prevent it from being subjected to inappropriate penalties under R1, R2, R3.6, and R8. | | | | | | | |

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

## Consideration of Comments on Draft Standard — MOD-001-1 — Project 2006-07

The ATC Standards Drafting Team thanks all commenters who submitted comments on the draft standard MOD-001-1. These standards were posted for a 30-day public comment period from April 16, 2008 through May 15, 2008. The stakeholders were asked to provide feedback on the standard through a special electronic Standard Comment Form. There were 37 sets of comments, including comments from 74 different people from approximately 50 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

There were many comments that led the drafting team to correct typographical errors, and to modify language to improve clarity, but none of the changes made by the drafting team changed the scope or intent of the requirements in the standard.

### Applicability

- Several entities have continued to express concern regarding the applicability of the ATC, TRM, and CBM standards. While the drafting team has attempted to write the standards in ways that are flexible and allow for organizational diversity, we note that FERC Order 890 makes reference to the use of Variances. Entities with non-traditional physical transmission markets or that have alternative ATC methodologies that meet or exceed the NERC ATC standards may wish to consider requesting one or more Variances related to these standards.

- Transmission Service Provider or Transmission Operator - The Drafting Team did not elect to change the entity that selects the methodology to the Transmission Service Provider; instead leaving it as the Transmission Operator. Based on the responses received, it appears that the industry remains divided on this question; only 13 of 35 comments received suggested that the entity should be the Transmission Service Provider. Reviewing comments made later related to this question, the Drafting Team does not find any clear rationale for selecting the Transmission Service Provider as the entity responsible for selecting the methodology. As discussed previously, the Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints. The SDT has reviewed this with the Functional Model Working Group in the past, and the FMWG was supportive of the SDT's interpretation. For those entities who believe the TSP to be the appropriate entity, we reiterate that options for delegation of this task exist. Transmission operators can simply defer to the decisions made by their Transmission Service Provider; if a more formal agreement and transfer of responsibility is needed, the Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service provider agreeing to take on responsibility for this requirement through written contract.

### Definitions

- Some entities expressed concerns with the definitions of Counterflows and Postbacks. The SDT does not believe that further definitions are necessary.

- The SDT modified the definition of ATC Path slightly to be clearer.

**Requirements**

- R1 - The SDT modified R1 to clearly identify the three methodologies for calculating ATC or AFC.

- R3.6 - Some entities did not completely understand the requirements related to explaining the processing of outages. The SDT modified R3.6 to be clearer.

- R3.6.3 - Several entities expressed uncertainty what the drafting team meant when referring to outages "that are unrecognized." The SDT clarified the requirement to require "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed."

- R6 and R7 - Several entities expressed concern with the drafting team's removal of the language requiring ATC/AFC assumptions to be "consistent" with those used in the planning of operations. The SDT attempted to consider the intent of the Order in its review of this requirement. It seems clear, from both a reading of the order and from comments submitted to the SDT, that FERC's intent is to ensure that service is not sold on a more conservative basis than the system has been planned for. Accordingly, the SDT modified this requirement to more closely align with this goal. Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards.

- R8.1 - Some entities requested a larger calculation grace period than 80 hours. The SDT extended the grace period to 175 hours, to be consistent with OASIS requirements.

  Some entities suggested that the "80-hour" allowance (now 175 hours) in R8.1 should not be in the requirement. The SDT disagrees, and believes that elimination of this form the standard would effectively require 100% availability of the calculation, which is not the intent of the drafting team.

  Some entities suggested that the allowance for a certain number of hourly calculations to be skipped did not specify that the allowance was only for software outages. The SDT felt that qualifying the limit as suggested would be difficult to verify objectively, as software outages vary in degree and impact.

- The SDT clarified R9.1 to indicate what information should be provided pursuant to requirement R9.

- Several entities suggested eliminating R2 and R8. The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives, and did not delete the requirements.

**Compliance**

- Some entities suggested adding language to the standard that the potential to count a single event as multiple violations was not allowed. The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.

- Some entities identified an overlap in the VSL for R3. The SDT corrected the overlap.

- Some commenters misunderstood the concept of time horizons, and the drafting team provided a summary of the use of time horizons to address these comments.

- All entities that responded indicated support for the new VRFs.

**Implementation Plan**

- Some entities expressed concern with the effective date and the "concurrent" implementation being dependent on "all" regulatory authorities. The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals.

**Concepts**

- Some entities questioned whether "internal ATC" should be required or posted. The SDT responded that the standard does not prohibit the use of Internal ATC, but that any suggestions to post it should be addressed through the NAESB process.

- Several entities did not understand why MOD-001 and MOD-030 both had requirements related to recalculation frequency. The SDT explained that these two requirements are different, and address fundamental differences between the methodologies.

- Several entities identified a concern with requiring "all" or "any" data. The SDT clarified that providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC.

- Some entities suggested R8 in MOD-001 and R10 in MOD-030 needed to be aligned. The SDT modified MOD-030 to address this.

- It was suggested that more detail needs to be developed for the treatment of counterflows. The SDT suggested the commenter develop a SAR in pursuit of this detail.

- The NERC RTOSDT expressed concern that the standard does not refer to Planning and operating limits. The SDT directed the RTOSDT to the specific areas in the methodology standard where such reference are made.

**Variances**

The SDT believes it may be helpful to the industry to review the process for Variances. The Variance process can work either concurrent with or independent of the development of a standard. Because the drafting team working on a particular standard is likely to already have the necessary expertise to participate in the development of the Variance, concurrent development is generally more efficient. However, this may not always be practical; in this case, standards drafting may proceed, and even complete, prior to the development and approval of Variances. In this case, entities should seek to develop those Variances and seek their approval prior to the effective date of the standard. An entity is not exempt from meeting the requirements of the standard if the effective date has passed and that entity is in the process of developing a Variance.

The NERC process allows for three different types of variances:

- An Entity Variance
- A Regional Variance less than an Interconnection
- A Regional Variance on Interconnection-Wide basis

The NERC Rules of Procedure  describe an Entity Variance as follows:

> Entity Variance — Any variance from a NERC reliability standard that is proposed to apply to one entity or a subset of entities within a limited portion of a regional entity, such as a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users, shall be approved through the regular standards development process defined in the NERC Reliability Standards Development Procedure and shall be made part of the applicable NERC reliability standard.

Entities seeking an Entity Variance should draft a SAR to request that Variance.  In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested.  Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately).  In both cases, the Variance will be compared to the standard to ensure the requester is addressing the reliability goals of the standard.  The ballot body is comprised of any member of the Registered Ballot Body that is interested and registers to join the ballot pool. Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe a Regional Variance Less Than an Interconnection as follows:

> Any regional variance from a NERC reliability standard that is proposed to apply for a regional entity, but not for an interconnection, shall be approved through the NERC Reliability Standards Development Procedure, except that only members of the registered ballot body located in the affected interconnection shall be permitted to vote; and the variance shall be made part of the applicable NERC reliability standard.

Entities seeking a Regional Variance Less Than an Interconnection should draft a SAR to request that Variance.  In that SAR, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested.  Such a variance can be addressed concurrently with a standard (e.g., balloted with the standard for which it applies) or subsequent to that standard's approval (balloted separately).  In both cases, the Variance will be compared to the standard to ensure the requestor is addressing the reliability goals of the standard.  The ballot body is comprised of any interested entities that that have registered with NERC and is a user, owner, or operator of facilities located within the interconnection in which the region requesting the Variance is located.   Once approved through the NERC standards development process, the Variance is filed with the appropriate regulatory authorities.

The NERC Rules of Procedure Describe a Regional Variance on an Interconnection-wide Basis as follows:

> An interconnection-wide regional variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the NERC reliability standard. NERC shall rebuttably presume that a regional variance from a NERC reliability standard that is developed, in accordance with a procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Entities seeking a Regional Variance on an Interconnection-wide Basis should draft that Variance using the regional standards development process described in the region's delegation agreement. In that Variance, the entity should clearly identify the need for the Variance, as well as how it meets the reliability objectives of the standard (or the specific requirements) for which the Variance is being requested. Once approved through the regional standards development process, the Variance should be brought to NERC for filing with the appropriate regulatory authorities.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving these standards forward to posting for pre-ballot consideration.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standard can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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1.

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Thad Ness | AEP | x | | x | | x | x | | | | |
| 2. | Anita Lee (G3) | AESO | | x | | | | | | | | |
| 3. | Helen Stines (G1) | Alcoa Power Generating, Inc. | x | | x | | | | | | | |
| 4. | Eugene Warnecke (G1) | Ameren | x | | x | | | | | | | |
| 5. | Allen Mosher | American Public Power Association | x | | | x | | x | | | | |
| 6. | Jason Shaver | American Transmission Company | x | | | | | | | | | |
| 7. | Jerry Smith (G2) | APS | x | | | | | | | | | x |
| 8. | Chris Bradley (G1) | Big Rivers Electric Cooperative | x | | x | | | | | | | |
| 9. | Denise Koehn | Bonneville Power Administration | x | | x | | x | x | | | | |
| 10. | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | x | | | | x | | | | | |
| 11. | Dave Lunceford (G2) | California ISO | | x | | | | | | | | x |
| 12. | Brent Kingsford (G3) | California ISO | | x | | | | | | | | |
| 13. | Paul Bleuss (G5) | California ISO | | x | | | | | | | | |
| 14. | Frank Cumpton | California ISO | | x | | | | | | | | |
| 15. | Paul Rocha | CenterPoint Energy | x | | | | | | | | | |
| 16. | Don Reichenbach (G1) | Duke Energy - Carolinas | x | | x | | | | | | | |
| 17. | Greg Rowland | Duke Energy Corporation | x | | x | | x | x | | | | |
| 18. | Reza Ebrahimian | Electric Service Delivery | x | | | | | | | | | |
| 19. | Jim Case (G5) | Entergy Services, Inc. | x | | | | | | | | | |
| 20. | Narinder K. Saini | Entergy Services, Inc. | x | | | | | | | | | |
| 21. | Joachim Francois (G1) | Entergy Services, Inc. | x | | x | | | | | | | |
| 22. | Jack Cashin/Barry Green | EPSA | | | | | x | x | | | | |
| 23. | H. Steven Myers (G3) (G5) | ERCOT ISO | | x | | | | | | | | |
| 24. | Doug Hohlbaugh | FirstEnergy | x | | x | | x | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
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| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 25. | Ralph Anderson (G5) | FMPA | | | | x | | | | | | |
| 26. | Earl Fair | Gainesville Regional Utilities | x | | x | | x | | | | | |
| 27. | Ross Kovacs (G1) | Georgia Transmission Corp. | x | | | | | | | | | |
| 28. | David Kiguel (G4) | Hydro One Networks | x | | x | | | | | | | |
| 29. | Alessia Dawes | Hydro One Networks | x | | x | | | | | | | |
| 30. | Roger Champagne (G4) | Hydro Quebec TransEnergie | x | x | | | | | | | | |
| 31. | Ron Falsetti (G3) | IESO | | x | | | | | | | | |
| 32. | Matt Goldberg (G3) | ISO-New England | | x | | | | | | | | |
| 33. | Kathleen Goodman (G4) | ISO-New England | | x | | | | | | | | |
| 34. | Maria Neufeld | Manitoba Hydro | x | | x | | x | x | | | | |
| 35. | Bill Phillips (G3) | MISO | | x | | | | | | | | |
| 36. | Jason Marshall (G5) | MISO | | x | | | | | | | | |
| 37. | Tom Mielnik | MRO NERC Standards Review Subcommittee | x | | x | | x | x | | | | |
| 38. | Jerry Tang (G1) | Municipal Electric Auth. of GA | x | | x | | | | | | | |
| 39. | Jim Case, Chair | NERC RTOSDT | x | x | | x | | | | | | |
| 40. | Rick Gonzales | New York Independent System Operator | | x | | | | | | | | |
| 41. | Greg Campoli (G4) | New York ISO | | x | | | | | | | | |
| 42. | Ralph Rufrano (G4) | New York Power Authority | x | | | x | x | x | | | x | |
| 43. | Rick White (G4) | Northeast Utilities | x | | | x | | | | | | |
| 44. | Guy V. Zito | NPCC | | | | | | | | | | x |
| 45. | Jim Castle (G3) | NYISO | | x | | | | | | | | |
| 46. | Greg Ward / Darryl Curtis | Oncor Electric Delivery | x | | | | | | | | | |
| 47. | Ron Falsetti | Ontario IESO | | x | | | | | | | | |
| 48. | Aaron Staley | Orlando Utilities Commission | x | | x | | x | | | | x | |
| 49. | Richard Kafka | Pepco Holdings, Inc. | x | | x | | x | x | | | | |
| 50. | Patrick Brown (G3) | PJM | | x | | | | | | | | |
| 51. | Al DiCaprio (G5) | PJM | | x | | | | | | | | |
| 52. | John Cummings (G4) | PPL EnergyPlus | | | | | | x | | | | |
| 53. | Jon Williamson (G4) | PPL EnergyPlus | | | | | | x | | | | |
| 54. | Mark Hemibach (G4) | PPL Generation/PPL EnergyPlus | | | | | x | x | | | | |
| 55. | Annette Bannon | PPL Supply Group | x | | x | | x | x | | | | |
| 56. | Phil Creech (G1) | Progress Energy - Carolinas | x | | x | | | | | | | |
| 57. | Phil Riley | Public Service Commission of South Carolina | | | | | | | | | x | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 58. | W. Shannon Black | Sacramento Municipal Utility District | | | x | | | | | | | |
| 59. | Pat Huntley (G1) | SERC | | | | | | | | | | x |
| 60. | John Troha (G1) | SERC | | | | | | | | | | x |
| 61. | Doug Bailey | SERC Available Transfer Capability Working Group (ATCWG) | x | | x | | | | | | x | |
| 62. | Vicky Budreau (G1) | So. Carolina Public Service Auth. | x | | x | | | | | | | |
| 63. | Al McMeekin (G1) | South Carolina Electric & Gas | x | | x | | | | | | | |
| 64. | Stan Shealy (G1) | South Carolina Electric & Gas | x | | x | | | | | | | |
| 65. | Jim Griffith | Southern Co. | x | | x | | | | | | | |
| 66. | DuShaune Carter (G1) | Southern Co. | x | | x | | | | | | | |
| 67. | Kevin Bates | Southwest Power Pool | | x | | | | | | | | |
| 68. | Charles Young | Southwest Power Pool | | x | | | | | | | | |
| 69. | Chuck Falls (G2) | SRP | x | | | | | | | | | x |
| 70. | Rex McDaniel | Texas-New Mexico Power Company | x | | | | | | | | | |
| 71. | John Harmon | The Midwest ISO | | x | | | | | | | | |
| 72. | John Dalessi | Transmission Agency of Northern California | x | | | | | | | | | |
| 73. | Brian Evans Mongeon G4) | Utilitiy Services, LLC | | | | | | x | | | | |
| 74. | Alice Druffel | Xcel Energy | x | | x | | x | x | | | | |

I — Individual
G1 — SERC Available Transfer Capability Working Group
G2 — WECC Market Interface Committee / Sub Commtt / ATC Task Force
G3 — ISO RTO Council/Standards Review Committee (SRC)
G4 — NPCC Regional Standards Committee
G5 — NERC RTO SDT

1. The drafting team modified several definitions in MOD-001 based on stakeholder comments. Do you agree with the revised definitions? If not, please specify any definition that you disagree with and, if possible, provide a suggested revision.

**Summary Consideration:**

Some entities expressed concerns with the definitions of Counterflows and Postbacks. The SDT does not believe that further definitions are necessary.

The SDT modified the definition of ATC Path as shown below to be clearer:

**ATC Path:** ~~Any Posted Path or a~~Any ~~other~~ combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| American Public Power Association | No - one or more definitions needs revision - see comments | "Counterflows" should be a defined term. It is used in MOD-1, MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-28-1 R10, for example, reads: "counterflows" are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID? This definition does not in any way describe what a counterflow is. "Postbacks" should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: "Postbacks" are changes to firm [non-firm] ATC [AFC] due to a change in the amount of Firm [non-firm] Transmission Service reserved or scheduled for a period, as defined in Business Practices. Postbacks are generally a positive quantity? Also, capitalize existing transmission commitments in the definition of ATC. |
| **Response:** The SDT has reviewed the standards, and finds that the definitions in MOD-001, the requirements for the ATCID in MOD-001, and the requirements and measures for calculating ATC in the methodologies all address this sufficiently. MOD-001 indicates in the definition that Postbacks are defined by business practices, while the individual methodology standards indicate that Postbacks are "changes to firm (non-firm) ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices." Counterflows is an industry term, and the manner in which it applies to these standards is described in the methodologies ("adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID"), as well as in MOD-001 R3.2. | | |
| Oncor Electric Delivery | No - one or more definitions needs revision - see comments | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). |
| **Response:** MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT | | |

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | | |
| Texas-New Mexico Power Company | No - one or more definitions needs revision - see comments | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company (TNMP) is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). |
| **Response:** MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*<br><br>. | | |

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| | | |
| Brazos Electric Power Cooperative, Inc. | No - one or more definitions needs revision - see comments | For the ERCOT region/market the concept of ATC, AFC are not applicable. It is suggested that the definition of ATC have some consideration for whether there is a required "commercial activity" for it in a region. |
| **Response:** MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | | |
| Duke Energy Corporation | No - one or more definitions needs revision - see comments | ATC path: Insert the phrase "or Available Flowgate Capability" after the phrase "Available Transfer Capability". |
| **Response:** The SDT does not agree that "AFC" should be included in the definition of ATC path. However, the SDT has modified the definition of ATC Path to clarify the intent of the definitions. | | |
| MRO NERC Standards Review Subcommittee | No - one or more definitions needs revision - see | The MRO supports the changes to the definitions. However, the MRO believes there is a need to define "counterflows." The MRO suggests that the SDT consider the following definition for Counterflows: "Counterflows are net impacts on a path or flowgate as determined by the Transmission Service Provider and specified in the appropriate implementation document."<br>**Response:** The SDT has reviewed the standards, and finds that the definitions in MOD-001, the requirements |

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| | comments | for the ATCID in MOD-001, and the requirements and measures for calculating ATC in the methodologies all address this sufficiently. Counterflows is an industry term, and the manner in which it applies to these standards is described in the methodologies ("adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID"), as well as in MOD-001 R3.2.<br><br>Capitalize "Existing Transmission Commitments" in the Available Transfer capability definition, since it is a defined term.<br>**Response:** The SDT has modified the definition of ATC as suggested (i.e., capitalizing ETC). |
| **Response:** Please see in-line response. | | |
| New York Independent System Operator | No - one or more definitions needs revision - see comments | The NYISO has continuing concerns with two of the revised definitions:<br><br>(i)"ATC Path;" and (ii) "ATC."<br>ATC Path:<br>The NYISO previously expressed concern with the SDT's use of a new defined term "ATC Path" instead of the term "Posted Path" that was used in earlier versions of MOD-001 and is more consistent with the terminology used in FERC's OASIS posting regulations. The NYISO continues to be concerned that the proposed definition of "ATC Path" set forth in the latest version of proposed MOD-001 could, absent revision or clarification, subject the NYISO to potential penalties that would be inappropriate given the nature of its financial reservation system and the inapplicability of certain OASIS posting requirements to it. Specifically, as the NYISO has explained in previous comments, ATC serves a fundamentally different purpose and is calculated differently in New York, because there are no express physical transmission reservations and all desired uses of the grid are accommodated to the extent that customers are willing to pay congestion. FERC has expressly recognized that the NYISO's ATC postings are merely advisory projections that may be of some commercial benefit to customers but that they do not determine whether customers can obtain transmission service. The NYISO has also explained that there are no "Posted Paths" as that term is defined under FERC's OASIS regulations internal to the NYISO and that the NYISO is not required, both because of that fact, and because of FERC orders exempting the NYISO from certain OASIS regulations, to post ATC on its internal interfaces for periods further out than one day-ahead. The current draft of MOD-001 would define "ATC Path" as including both "Posted Paths" and "any other combination of Point of Receipt and Point of Delivery for which Available Transfer Capability is calculated." The NYISO remains concerned that without clarification this definition could be interpreted in a way that would require the NYISO to post ATC for time periods further out than one day ahead when it is not required by FERC's regulations to make such postings and where such postings would serve no reliability purpose (because they have nothing to do with scheduling or "over-scheduling" long-term transactions.) Given the nature of the NYISO's financial reservation system, and the central role that the output of its day-ahead and real-time market software plays in its ATC calculations (see below), the NYISO would not have any meaningful information to post for periods further out than one day-ahead in any case. The NYISO therefore respectfully requests that the SDT either: (i) remove the defined |

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| | | term “ATC Path” and return to the use of “Posted Path” as that term is defined in FERC’s OASIS regulations; or (ii) revise the term ?ATC Path? as follows: ATC Path: Any Posted Path or any other combination of Point of Receipt and Point of Delivery for which Available Transfer Capability is calculated, provided, however, that interfaces or paths for which a Transmission Service Provider is not required under FERC’s regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead shall not be considered to be ATC Paths? The NYISO’s proposed revision would apply to few Transmission Service Providers, and thus would not undermine the proposed requirements or harm reliability. It would, however, be a very important accommodation to the NYISO that would prevent it from being subjected to inappropriate penalties under R1, R2, or R8.<br><br>Available Transfer Capability (“ATC”): The proposed new definition of “ATC” does not appear to be flexible enough to accommodate the fundamentally different nature of ATC under the NYISO’s FERC-approved financial reservation transmission model. As the NYISO has previously explained, a customer’s ability to schedule transactions in the NYISO system is not limited by a pre-defined amount of ATC. In New York ATC is not, in the SDT’s words, ?a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.? Instead, ATC postings are really “advisory projections” calculated after the NYISO markets close, and transactions are scheduled, based on calculations performed by the NYISO’s day-ahead and real-time market software. The fact that a posted ATC is zero does not mean that further commercial activity is precluded because the NYISO may redispatch its system to support additional transactions. A posted ATC value of zero simply indicates that there is congestion at a particular NYISO interface. FERC has granted the NYISO a number of waivers from its OASIS regulations that reflect these differences and has recognized that ATC is merely an ?advisory projection? in New York. The NYISO therefore respectfully requests that the SDT accommodate the different nature of ATC under the NYISO’s FERC-approved financial transmission model by either: (i) deleting the proposed definition of ATC; or (ii) specifying that each Transmission Service Provider must include its definition of ATC in its ATCID (and expressly allowing entities such as the NYISO to have definitions that vary from the standard definition); or (iii) revising the definition as follows: Available Transfer Capability (ATC): A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows, except with respect to Transmission Service Providers that employ FERC-approved financial reservation transmission models in which ATC serves as an advisory projection of potential transmission congestion.? Again, the NYISO’s proposed revision would not apply to many Transmission Service Providers, and thus would not undermine the proposed standard or harm reliability. It would, however, be a very important accommodation to the NYISO that would prevent it from being subjected to inappropriate penalties under R1, R2, R3.6, and R8. |
| **Response:** The Drafting Team has changed the definition of ATC Path slightly to be clearer, but believes that the definition of ATC Path is correct. MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to | | |

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. The SDT understands that while NYISO calculates ATC values on its internal interfaces, those internal interfaces do not meet the definition of an ATC Path, i.e., they are not described by a POR/POD combination and they are not a FERC Posted Path.<br><br>Regarding the definition of ATC, the SDT believe the definition proposed is correct. Based on NYISO's description, it sounds as if the NYISO is not actually posting ATC, but "advisory projections." The SDT believes that if this is correct, the NYISO may not actually have any paths that qualify as Posted Paths.<br><br>Note that NYISO may wish to pursue a Variance to this standard. | | |
| American Transmission Company | No - one or more definitions needs revision - see comments | Capitalize "Existing Transmission Commitments" in the Available Transfer capability definition, since it is a defined term.<br><br>**Response:** The SDT has modified the definition of ATC as suggested (i.e., capitalizing ETC).<br><br>We do not believe that the SDT has to provide a definition of ATCID. Requirement 3 outlines the specifics of ATCID and we find the definition unnecessary. The SDT should explain why this definition is necessary.<br><br>**Response:** The definition of ATCID has been provided based on previous comments provided by the industry. Additionally, use of this definition allows NAESB to easily refer to these documents within their standards. |
| **Response:** Please see in-line responses. | | |
| California ISO | Yes - definitions are acceptable as revised | Please see comments given ion last question. |
| **Response:** Please see response to last question. | | |
| Entergy Services Inc | Yes - definitions are acceptable as revised | Revised definitions are acceptable |
| SERC Available Transfer Capability Working Group (ATCWG) | Yes - definitions are acceptable as revised | |
| The Midwest ISO | Yes - definitions are acceptable as revised | |
| Transmission Agency of Northern California | Yes - definitions are acceptable as revised | |
| WECC Market | Yes - definitions are acceptable as revised | |

| Organization/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| Interface Committee / Sub Commtt / ATC Task Force | | |
| Southwest Power Pool | Yes - definitions are acceptable as revised | |
| Manitoba Hydro | Yes - definitions are acceptable as revised | |
| EPSA | Yes - definitions are acceptable as revised | |
| Public Service Commission of South Carolina | Yes - definitions are acceptable as revised | |
| ISO RTO Council/Standards Review Committee (SRC) | Yes - definitions are acceptable as revised | |
| ERCOT ISO | Yes - definitions are acceptable as revised | |
| Orlando Utilities Commission | Yes - definitions are acceptable as revised | |
| PJM | Yes - definitions are acceptable as revised | |
| NERC RTOSDT | | |
| NPCC Regional Standards Committee | Yes - definitions are acceptable as revised | |
| FirstEnergy | Yes - definitions are acceptable as revised | |
| AEP | Yes - definitions are acceptable as revised | |
| Bonneville Power Administration | Yes - definitions are acceptable as revised | |
| Xcel Energy | Yes - definitions are acceptable as revised | |
| Gainesville Regional Utilities | Yes - definitions are acceptable as revised | |
| Ontario IESO | Yes - definitions are acceptable as revised | |
| Hydro One Networks | Yes - definitions are acceptable as revised | |

2. MOD-001-1, R1 says, “Each Transmission Operator shall select one methodology for calculating the available capability on the bulk electric system…” The Drafting Team believes that the Transmission Operator is the appropriate entity since the Transmission Operator is ultimately responsible for operating a reliable system while using all Transmission Service Providers’ calculated available capability. However, some parties have commented that the Transmission Service Provider should select the methodology for calculating the available capability since (a) a Transmission Service Provider may use the transmission of multiple Transmission Operators, (b) there are 'registered' Transmission Operators that do not calculate ATC, and (c) the Transmission Operator has only 2 responsibilities — R1 to pick a calculation method, and R6 where the Transmission Operator must calculate consistent with planning studies.

   Should the Transmission Operator or the Transmission Service Provider select the methodology for calculating the available capability on the bulk electric system?

**Summary Consideration:** The Drafting Team appreciates the input provided by the industry regarding this question. Based on the responses received, it appears that the industry remains divided on this question; only 13 of 35 comments received suggested that the entity should be the Transmission Service Provider. Reviewing comments made later related to this question, the Drafting Team does not find any clear rationale for selecting the Transmission Service Provider as the entity responsible for selecting the methodology. As discussed previously, the Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining the methodology used to determine TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints. The SDT has reviewed this with the Functional Model Working Group in the past, and the FMWG was supportive of the SDT’s interpretation.

For those entities who believe the Transmission Service Provider to be the appropriate entity, we reiterate that options for delegation of this task exist. Transmission Operators can simply defer to the decisions made by their Transmission Service Provider; if a more formal agreement and transfer of responsibility is needed, the Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service Provider agreeing to take on responsibility for this requirement through written contract.

| Organization/Group | Question 2: |
|---|---|
| PJM | Transmission Operator |
| Duke Energy Corporation | Transmission Operator |
| Bonneville Power Administration | Transmission Operator |
| Pepco Holdings, Inc. | Transmission Operator |
| Entergy Services Inc | Transmission Operator |
| American Transmission Company | Transmission Operator |
| Brazos Electric Power Cooperative, Inc. | Transmission Operator |
| Manitoba Hydro | No Preference |

| Organization/Group | Question 2: |
|---|---|
| Transmission Agency of Northern California | No Preference |
| SERC Available Transfer Capability Working Group (ATCWG) | No Preference |
| EPSA | No Preference |
| Public Service Commission of South Carolina | No Preference |
| Oncor Electric Delivery | No Preference |
| The Midwest ISO | Transmission Service Provider |
| WECC Market Interface Committee / Sub Commtt / ATC Task Force | Transmission Service Provider |
| American Public Power Association | Transmission Service Provider |
| ERCOT ISO | Transmission Service Provider |
| Orlando Utilities Commission | Transmission Service Provider |
| NPCC Regional Standards Committee | Transmission Service Provider |
| FirstEnergy | Transmission Service Provider |
| AEP | Transmission Service Provider |
| Gainesville Regional Utilities | Transmission Service Provider |
| MRO NERC Standards Review Subcommittee | Transmission Service Provider |
| Ontario IESO | Transmission Service Provider |
| Hydro One Networks | Transmission Service Provider |
| New York Independent System Operator | Transmission Service Provider |

3. The drafting team modified some requirements and associated measures in MOD-001 to reflect industry concerns. If there are any requirements or measures that you believe are incorrect, please identify them for us, being as specific as possible with a suggestion for revising the language so you believe it is correct.

**Summary Consideration:**

R1 - The SDT modified R1 to clearly enumerate the three methodologies.

R3.3 - The SDT made some changes to address appropriate inclusion of "AFC".

R3.6 - Some entities did not completely understand the requirements related to explaining the processing of outages. The SDT modified R3.6 to be clearer.

R6, R7 - Several entities expressed concern with the drafting team's removal of the language requiring ATC/AFC assumptions to be "consistent" with those used in the planning of operations. The SDT attempted to consider the intent of the Order in its review of this requirement. It seems clear, from both a reading of the Order and from comments submitted to the SDT, that FERC's intent is to ensure that service is not sold on a more conservative basis than the system has been planned for. Accordingly, the SDT modified these requirements to more closely align with this goal. Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards.

R8 - Some entities suggested that the "80-hour" allowance should not be in the requirement. The SDT disagrees, and believes that elimination of this form the standard would effectively require 100% availability of the calculation, which is not the intent of the drafting team. Some entities requested a larger calculation grace period than 80 hours. The SDT extended the grace period to 175 hours, to be consistent with OASIS requirements.

R9.1 - The SDT clarified R9.1 to indicate what information should be provided pursuant to requirement R9.

VSLs - Several entities suggested eliminating R2 and R8. The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives.

Some entities questioned whether "internal ATC" should be required or posted. The SDT responded that the standard does not prohibit the use of Internal AT, but that any suggestions to post it should be addressed through the NAESB process.

Several entities did not understand why MOD-001 and MOD-030 both had requirements related to recalculation frequency. The SDT explained that these two requirements are different, and address fundamental differences between the methodologies.

Several entities identified a concern with requiring "all" or "any" data. The SDT clarified that providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC.

Several entities expressed uncertainty what the drafting team meant when referring to outages "that are unrecognized." The SDT clarified the requirement to require "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed."

The SDT also modified the standard to address several minor language changes and corrections.

| Organization/Group | Question 3 - Incorrect Requirement(s) or Measure(s): |
| --- | --- |
| American Public Power Association | R3.3 - seems awkward for transfer capability to not be a defined term when TTC and ATC are defined; at minimum, edit to read transfer or Flowgate capability. |

| Organization/Group | Question 3 - Incorrect Requirement(s) or Measure(s): |
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| | **Response:** The SDT has modified R3.3 to include flowgate capability, but has also clarified that since this applies to the Transmission Service provider, it only refers to "Available" capacity (since the Transmission operator is the entity that calculates Total Transfer/Flowgate Capability).<br><br>R3.6 - clarify that "outages" are transmission outages, generator outages or both.<br>**Response:** The SDT has clarified R3.6 as suggested.<br><br>R8.1 - why hardwire 80 hours per calendar year during which calculations are not required to be performed? Should this be a compliance Measure?<br>**Response:** The SDT has incorporated the allowance into the requirement to ensure that compliance is actually judged based on the requirement. The measure is intended to demonstrate how compliance can be verified, not modify the requirement to be less stringent. |
| **Response:** Please see in-line responses. | |
| The Midwest ISO | R3.3 - last line should read: calculating ATC or AFC.<br>**Response:** The SDT has modified R3.3 to include flowgate capability, but has also clarified that since this applies to the Transmission Service provider, it only refers to "Available" capacity (since the Transmission operator is the entity that calculates Total Transfer/Flowgate Capability).<br><br>R3.4 - last line should read: "calculating ATC or AFC.<br>**Response:** The posted version of the standard refers to ATC, AFC, TTC, and TFC, and the SDT believes the language used is appropriate.<br><br>R3.5 – Each bullet should read: "allocate ATC or AFC?<br>**Response:** to the posted version of the standard refers to ATC, AFC, TTC, and TFC, and the SDT believes the language used is appropriate.<br><br>R6 and R7" The term "assumptions" is not specific enough for entities to prepare for compliance. The Midwest ISO requests the standard to list specific assumptions within the scope and what defines "more limiting' for each of them. For example, is load assumption within the scope? If yes, what load assumption is more limiting? If it is not possible, the Midwest ISO believes that this topic from Order 890 should be left out from any standard and left to FERC to address issues on a case by case basis.<br>**Response:** The assumptions are generally those defined in the ATC methodologies (MOD-028, MOD-029, and MOD-030). To the extent other assumptions used in the ATC processes are described in the ATCID, they should be considered as well. |

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| | R9 - Please expand/clarify the intentions of the 4th bullet. What specific aggregated firm capacity is being referenced? Capacity in ETC for each flowgate as specified by reservations? An example would be very beneficial.<br>**Response:** The SDT uses the term "aggregated" to mean that the requirement refers to the sum of the uses, not individual schedules.<br><br>R9? The 13th bullet should read: "(TRM), and TTC or TFC for all".<br>**Response:** The SDT has deleted "TTC" from the requirement, as it appears to be an editing error.<br><br>M6 - Include reference for TFC, should read: "used for TTC, or TFC, and Operations Planning."<br>**Response:** The SDT has modified the measure as suggested. |
| **Response:** Please see in-line responses. | |
| WECC Market Interface Committee / Sub Commtt / ATC Task Force | MOD-01, R9. Could the NERC Team please clarify "which" Load Forecast it is requesting? Hourly? Daily? For what affected area - ?<br>**Response:** The SDT has modified R9.1 to be clear that the intention is for the provision of the load forecast that is used in the ATC/AFC process. To the extent that no forecast is used in the ATC/AFC process, but one exists, that one must be provided.<br><br>MOD-01, R9. Could the NERC Team please clarify that Block/Dispatch Order and Participation Factors do not call for the submission of specific schedules; rather, these definitions only call for dispatch rules from which approximations can be made.<br>**Response:** The SDT notes that these have been proposed to be defined terms, and that the proposed definitions align with the suggested improvements made by WECC. |
| **Response:** Please see in-line responses. | |
| EPSA | R6/7. I believe the wording of this requirement in the previous draft was superior. In the revised language, deletion of the word "consistent" allows for discontinuities in the ATC calculations. For example, if the assumptions used in "planning of operations" in the period beyond one month are different than for those in the current month, this could create discontinuities where the calculations adopt different assumptions. In addition, the current language has broken the explicit link between planning studies and operations studies. |
| **Response:** The SDT attempted to consider the intent of the Order in its review of this requirement. It seems clear, from both a reading of the order and from comments submitted to the SDT, that FERC's intent is to ensure that service is not sold on a more conservative basis than the system has been planned for. Accordingly, the SDT modified these requirements to more closely align with this goal. | |

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| Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards.<br><br>Regarding "planning studies and operations studies," the drafting team carefully reviewed Order 890, and modified the language to be consistent with that used in the Order. The Order specifically refers to the "planning of operations," not "planning and operations." The SDT believes this to be a specific reference to the Operations Planning timeframe. | |
| ISO RTO Council/Standards Review Committee (SRC) | Requirement 2?While the IRC understands that the SDT believes that the requirements need to address the amount of ATC or AFC data calculated and the frequency of calculation associated with them, these requirements should be business practices and should be considered NAESB scope and eliminated from the MOD Standards. The MODs can still address FERC orders and be reliability based without the MOD-001 R2 (amount of ATC or AFC) and R8 (frequency ATC recalculation) and MOD-030 R10 (frequency AFC recalculation) requirements.<br>**Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives.<br><br>The violation severity levels for these draft standards now have a graded implementation. The possibility of multiple violations resulting from a single event still remains. The IRC requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. This language should be added to the standard as a new item 6 to section A of MOD-001.<br>**Response:** The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity Levels in an attempt to eliminate the potential for multiple violations due to single events.<br><br>Requirement 3 -R3.2.1 - The IRC understands the SDT's reasons for using "Confirmed" reservations in accordance with the FERC regulations. However, reservations that are in "Accepted", as well as, "Confirmed" status should be included. Once service is "Accepted" by a TSP it cannot be retracted. Using reservations that are in "Accepted" and "Confirmed" status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TSP from decrementing for accepted and confirmed TSRs. We understand that some TSPs maintain two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TSPs who maintain two sets of ATC values to post the "internal" ATC values to provide greater transparency and give customers a more accurate picture of capability available to new requests?<br>**Response:** The standard does not prohibit the TSP from maintaining an "internal" ATC value for use in approving reservation requests that includes these Accepted reservations. To the extent the IRC |

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| | believes these numbers should be posted, the SDT believes the IRC should develop a NAESB request for the posting of this information.<br><br>R3.6 - For R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD 1 and applied consistently across MODS 28, 29 and 30.<br>**Response:** MOD-001 R3.6 does not specify which calculations the outages have to be used in - it requests clarification of outage processing rules for outages that are in effect for partial days or months. We have clarified MOD-001 to make this more easily understood.<br><br>MOD-030 R5.2 requires those outages to be used in the AFC process, and requires that the outage processing rules from the ATCID be used. This is the same requirement for MOD-028 R3. Due to differences in the nature of the Rated System Path methodology, MOD-029 uses outages in a different fashion, but includes their consideration in R2.<br><br>Requirement 8 ?If R8 is not moved to NAESB Business Practices then revise R8.1 and the VSL to align the requirement and NAESB practice which allows OASIS to be down 2% of the time over a year. Modify the 80 hour per year allowable outage requirement to 175 hours per year (8760 hrs/year x 0.02= 175 hours). This VSL does not become a possible sanction until the accumulated amount of hours missed exceeds 175 hours. The 175 hours is for planned, system IT outages. Unplanned, system IT outages should not be included in this total.<br>**Response:** The drafting team has modified the requirement to allow for 175 hours of outage as suggested. However, the SDT believes that this time is sufficient to include both planned and unplanned outages. |
| **Response:** Please see in-line responses. | |
| ERCOT ISO | Requirement 1:I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall select one ATC methodology for calculating ATC (Area Interchange methodology, Rated System Path methodology)or AFC (Flow gate methodology) for each ATC Path per time period identified in R2 for those facilities within its Transmission Service Provider area. "Comment: The TOP is to operate its transmission operating area in a reliable manner and ensure SOLs are determined. ATC is a transmission service market concept, not a reliability function. In areas where there is a transmission service market in operation, there is some reliability value to having a representative ATC in play to ensure proper planning is conducted, but reliability is ensured by adherence to the SOLs of the system, not by adherence to ATC.<br>**Response:** The requirement currently applies only to ATC Paths. The SDT believes adding this statement again would be redundant and add no value to the standard. |

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| | Requirement 3:I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: "<br>**Response:** The SDT does not believe it is appropriate to exempt an entity from documenting the information described. To the extent an entity has not ATC paths, they may so document where appropriate. However, the other information should be included in support of coordination with other entities.<br><br>Requirement 4:I suggest modifying the requirement to state: "The Transmission Service Provider with ATC Path(s) shall notify the following entities (via electronic mail) before implementing a new or revised ATCID ."<br>**Response:** The SDT does not believe it is appropriate to exempt an entity from notifying the listed entities of changes to the documentation described.<br><br>Requirement 5:I suggest modifying the requirement to state: "The Transmission Service Provider with ATC Path(s) shall make available the current ATCID to all of the entities specified in R4."<br>**Response:** The SDT does not believe it is appropriate to exempt an entity from providing the listed entities with the documentation described.<br><br>Requirement 6:I suggest modifying the requirement to state: "When calculating TTC or TFC, the Transmission Service Provider with ATC Path(s) shall use assumptions no more limiting than the estimated SOLs used in planning of operations for the corresponding time period studied. "<br>**Response:** If an entity is not calculating TTC or TFC, the requirement does not apply. To the extent an entity does calculate these values, they are expected to comply.<br><br>Requirement 7:I suggest modifying the requirement to read: "When calculating ATC or AFC, the Transmission Service Provider with ATC Path(s) shall use assumptions no more limiting than the estimated SOLs used in planning of operations for the corresponding time period studied."<br>**Response:** The SDT has already included references to SOLs in other areas of the standard, and does not believe they need to be added to this requirement.. While not included in MOD-001, the other posted methodology standards include references to SOLs. These references are as follows: MOD-028 R6.1; MOD-029 R3; MOD-030 R2.4.<br><br>Requirement 8:I suggest modifying the requirement to state: "Within 30 calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, or Reliability Coordinator for data |

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| | from the list below for use in ATC or AFC calculations, each Transmission Service Provider with ATC Path(s) receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2."<br>**Response:** Assuming this comment applies to R9, the SDT believes that all Transmission Service Providers should be willing to share this information with it neighbors in the interest of ensuring reliable and accurate calculation of ATC.<br><br>Requirement 9.1:I suggest modifying the sub-requirement to state: "The Transmission Service Provider with ATC Path(s) shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months in the future (subject to confidentiality and security requirements)."<br>**Response:** The SDT believes that all Transmission Service Providers should be willing to share this information with it neighbors in the interest of ensuring reliable and accurate calculation of ATC.<br><br>Requirement 9.2:I suggest modifying the sub-requirement to state: "This data shall be made available by the Transmission Service Provider with ATC Path(s) on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requestor and the provider)."<br>**Response:** The SDT believes that all Transmission Service Providers should be willing to share this information with it neighbors in the interest of ensuring reliable and accurate calculation of ATC |
| **Response:** Please see in-line responses. | |
| PJM | Requirement 2? While PJM understands that the SDT believes that the requirements need to address the amount of ATC or AFC data calculated and the frequency of calculation associated with them, these requirements should be business practices and should be considered NAESB scope and eliminated from the MOD Standards. The MODs can still address FERC orders and be reliability based without the MOD-001 R2 (amount of ATC or AFC) and R8 (frequency ATC recalculation) and MOD-030 R10 (frequency AFC recalculation) requirements.<br>**Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives.<br><br>The violation severity levels for these draft standards now have a graded implementation. The possibility of multiple violations resulting from a single event still remains. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. This language should be added to the standard as a new item 6 to section A of MOD-001.<br>**Response:** The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of |

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| | the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events.<br><br>Requirement 3 - R3.2.1 - PJM understands the SDT's reasons for using "Confirmed" reservations in accordance with the FERC regulations. However, reservations that are in "Accepted", as well as, "Confirmed" status should be included. Once service is "Accepted" by a TSP it cannot be retracted. Using reservations that are in "Accepted" and "Confirmed" status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TP from decrementing for accepted and confirmed TSRs. We understand that some TPs maintain two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TPs who maintain two sets of ATC values to post the "internal" ATC values to provide greater transparency and give customers a more accurate picture of capability available to new requests.?<br>**Response:** The standard does not prohibit the TSP from maintaining an "internal" ATC value for use in approving reservation requests that includes these Accepted reservation. To the extent the IRC believes these numbers should be posted, the SDT believes the IRC should develop a NAESB request for the posting of this information.<br><br>R3.6 - For R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD 1 and applied consistently across MODS 28, 29 and 30.<br>**Response:** MOD-001 R3.6 does not specify which calculations the outages have to be used in - it requests clarification of outage processing rules for outages that are in effect for partial days or months. We have clarified MOD-001 to make this more easily understood.<br><br>MOD-030 R5.2 requires those outages to be used in the AFC process, and requires that the outage processing rules from the ATCID be used. This is the same requirement for MOD-028 R3. Due to differences in the nature of the Rated System Path methodology, MOD-029 uses outages in a different fashion, but includes their consideration in R2.<br><br>Requirement 8? If R8 is not moved to NAESB Business Practices then revise R8.1 and the VSL to align the requirement and NAESB practice which allows OASIS to be down 2% of the time over a year. Modify the 80 hour per year allowable outage requirement to 175 hours per year (8760 hrs/year x 0.02= 175 hours). This VSL does not become a possible sanction until the accumulated amount of hours missed exceeds 175 hours. The 175 hours is for planned, system IT outages. Unplanned, system IT outages should not be included in this total.<br>**Response:** The drafting team has modified the requirement to allow for 175 hours of outage as |

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| | suggested. However, the SDT believes that this time is sufficient to include both planned and unplanned outages. |
| **Response:** Please see in-line responses. | |
| NPCC Regional Standards Committee | NPCC Participating Members have the following comments on specific requirements1. R3.6.3: This subrequirement is too vague and its addition is not necessary. Subrequirements R3.6.1 and R3.6.2 suffice to hold the TSP responsible for considering the impact of outages in ATC calculation. How the outages are processed has no bearing on the ultimate scenarios (topologies) that the TSP must consider.<br>**Response:** The SDT has modified the standard to more clearly indicate that the ATCID should document how to utilize partial outages within the ATC/AFC process.<br><br>2. Also we do not agree with the changes made to R6 and R7. By "no more limiting than" the assumptions used in planning of operations for the same time period, it would imply that the TOP and TSP may use less restrictive (or more liberal) assumptions. The results could be that the TTCs and ATCs are higher than the planned operational parameters, giving rise to potential unreliability. We do not see a problem with the previous wording of ?consistent with?, and this should be reinstated<br>**Response:** The SDT attempted to consider the intent of the Order in its review of this requirement. It seems clear, from both a reading of the order and from comments submitted to the SDT, that FERC's intent is to ensure that service is not sold on a more conservative basis than the system has been planned for. Accordingly, the SDT modified this requirement to more closely align with this goal.<br><br>Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards. |
| **Response:** Please see in-line responses. | |
| FirstEnergy | R1- The selection of a calculation methodology should reside with the party responsible for calculating ATC. As stated in question 2, FE believes that R1, the selection of an ATC methodology, should be applicable to the Transmission Service Provider (TSP) and not the Transmission Operator since within many RTO areas it is the TSP who maintains the ATC methodology documentation and performs the ATC calculations. This is the case in a large portion of the continent and a standard should not be written in a way that would knowingly require an assignment delegation for a large number of potential responsible entities. Assigning the requirement responsibility to the TSP would also work for non-market areas of the continent where a TO/TOP also serves as its own its own TSP. The TOP should provide a support role in providing data and information that is needed by the TSP to fulfill its responsibilities in calculating ATC. The TSP is overseeing transmission service requests and making determination of the viability of such requests. The TOP has ultimate reliability responsibility in the real-time environment and will manage its system to its system operating limits regardless of the ATC |

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| | methodology used by its TSP to approve transactions that make use of the transmission operator's system.<br>**Response:** Please see summary response to Question 2.<br><br>R3.3 - There appears to be a typo. Replace "of" in the words "transfer of Flowgate capability" with "or"<br>**Response:** The SDT has modified the document to rectify this error.<br><br>R3.3, R3.4, R3.5 - Suggest the SDT consider replacing the words "transfer or Flowgate capability" with "ATC or AFC" to improve<br>**Response:** The SDT has modified R3.3 in response to this comment. In R3.4 and R3.5, the language has been left as written, as it is intended to cover ATC, AFC, TTC, and TFC.<br><br>R3.6 - Replace "ATC" with "ATC or AFC".<br>**Response:** The SDT has modified R3.6 to incorporate flowgate values.<br><br>R3.6 (sub-requirements) - The sub-requirements of R3.6 require that outages be included in the daily and monthly calculations, but excludes hourly calculation periods. In MOD-030 (AFC Methodology) requirement R5.2 requires expected transmission and generation outages are included for all applicable time period calculated. It is suggested that a single requirement reside in MOD-001 to cover the hourly, daily and monthly aspects for this intent that would assure consistent application across the MOD-028, MOD-029 and MOD-030 standards.<br>**Response:** MOD-001 R3.6 does not specify which calculations the outages have to be used in - it requests clarification of outage processing rules for outages that are in effect for partial days or months. We have clarified MOD-001 to make this more easily understood.<br><br>MOD-030 R5.2 requires those outages to be used in the AFC process, and requires that the outage processing rules from the ATCID be used. This is the same requirement for MOD-028 R3. Due to differences in the nature of the Rated System Path methodology, MOD-029 uses outages in a different fashion, but includes their consideration in R2.<br><br>R8 - It is not clear why the frequency for recalculation is only focused on ATC, and does not read "ATC or AFC", similar to the wording used for calculating in R2. In MOD-030 R10 addresses recalculation for the AFC but it seems that with the suggested change in R8 of MOD-001, that R10 of MOD-030 could be eliminated. Additionally they are inconsistent in that R10 does not provide for the 80 hour annual |

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| | allowance that is stated in R8.<br>**Response:** These two requirements are different, and address fundamental differences between the methodologies. MOD-001 discusses the recalculation of ATC on a fixed schedule unless the components in the ATC equation change. MOD-030 R10 addresses calculation of AFC on a schedule consistent with the MOD-001 requirement. However, there is additional information in the MOD-030 requirement that is specific to that methodology. MOD-030 R10 does not require full recalculation of the distribution factors through an update of the transmission model; updates of the transmission model occur on a separate schedule as defined in MOD-030 R3. MOD-028 addresses this similarly through the recalculation of TTC on a separate schedule as defined in MOD-028 R5. MOD-029 addresses changes to topology through adjustments to TTC. Because of these technical differences between the methodologies, the SDT believes having the two requirements is appropriate.<br><br>The SDT has modified MOD-030 R10 to allow for the annual allowance specified in R8. |
| **Response:** Please see in-line response. | |
| PPL Supply Group | R4. PPL suggests that Purchasing/Selling Entities should be included in the listing of entities under Requirement R4 who have access to the ATCID.<br>**Response:** The SDT is not addressing access of Transmission Customers to this information. NAESB will be drafting standards that address this requirement.<br><br>R8. PPL suggests that the following changes be made to the calculation time periods : R8.1 should require hourly ATC to be calculated ?as close to continuously as possible?. Once per hour is too slow.R8.2 should require daily ATC to be calculated at 15 minute or less intervals. Once per day is too slow.R8.3 should require that Monthly ATC be calculated hourly or at most daily. Once per week is too slow.<br>**Response:** The standard is establishing a minimum set of requirements. Note that Transmission Service Providers may calculate more often if desired. |
| **Response:** Please see in-line responses. | |
| Duke Energy Corporation | R8.1 - The following sentence, ?Transmission Service Providers are allowed up to 80 hours per calendar year during which calculations are not required to be performed.? Appears somewhat capricious and should be clarified to show the drafting team's intentions. As presented, it would permit a TP to decide not to calculate hourly ATC for a 3 1/3 day period. Also, R8 does not require recalculation if none of the calculated values identified in the ATC equation have changed. Does R8.1 limit the exemption provided in R8 to 80 hours per year?<br>**Response:** No. The SDT has modified R8.1 to make this clearer. |

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| | M7 - insert the phrase "list of contingencies," before the phrase "loop flow".<br>**Response:** The SDT has modified the standard as suggested. |
| **Response:** Please see in-line responses. | |
| Xcel Energy | 1) R3.6.3 Need to strike "that are unrecognized". The term "unrecognized" is problematic and vague.<br>**Response:** The SDT has modified the requirement to be more explicit by requiring "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed."<br><br>2) R3.2.2 Please clarify what you mean by "defined accounting".<br>**Response:** The SDT has modified the standard to reference R3.2, rather than simply using the words above.<br><br>3) R3.3 There is a typo. Please change "of" to "or".<br>**Response:** The SDT has modified the standard as suggested. |
| **Response:** Please see in-line responses. | |
| Gainesville Regional Utilities | R1: In reading the standard and the definitions, it seems that the std. doesn't require an entity to calculate TTC/TFC/AFC, but only tells them how it must be done if it is to be done at all. Am I understanding this requirement correctly?<br>**Response:** R1 requires that if a Transmission Operator has "ATC paths," it must choose a methodology. R2 requires the Transmission Service Provider to use that methodology. To the extent a Transmission Operator has no ATC paths, the associated Transmission Service Provider would not be obligated to calculate ATC/TTC/TFC/AFC.<br><br>R6: If the responsible entity is changed in R1, with it also be changed in this requirement as well?<br>**Response:** No. The Transmission Operator remains responsible for determining TTC and/or TFC.<br><br>R6&7: If for example a study for month 10 may not have a corresponding "planning of operations" activity, what action is required to fulfill this requirement?<br>**Response:** The SDT has modified the requirement to clarify that if a study has not been undertaken for a specific period, there is no requirement for the assumptions to be no more limiting than those used in the study.<br><br>R6&7: What is meant by " assumptions"? Can the team provide some GOOD examples?<br>**Response:** The SDT has provided several examples within the measures for the requirement. |

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| | R6&7: I do not see a reliability purpose of these 2 requirements. I do not see how setting a maximum threshold on limiting assumptions can support a reliability interest.<br>**Response:** FERC identified in Order 890 that this “Predictable, sufficiently accurate, consistent, equivalent, and replicable results promote reliability.” The drafting team concurs. |
| **Response:** Please see in-line responses. | |
| Pepco Holdings, Inc. | PHI supports the comments of PJM and will not duplicate the submission of comments |
| **Response:** Please see response to PJM comments. | |
| MRO NERC Standards Review Subcommittee | 1. The MRO agrees with the changes made to replace "ATC" with "ATC or AFC" in the standards. However, the MRO believes this change should be made to R3.6 should be revised this way as well to say "A description of how outages are considered in ATC or AFC calculations, including:".<br>**Response:** The SDT has modified the requirement to include flowgates.<br><br>2. The MRO continues to believe that R4 should be revised to match M4 "The Transmission Service Provider shall provide evidence (such as dated electronic mail messages) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)" The MRO does not see the reliability need to specify the media via how the Transmission Service Provider notifies the following entities. However, if the issue is that the SDT believes that there must be a record of the notification, the MRO suggests that the words "in writing" be used allowing the Transmission Service Provider to determine the media of notification.<br>**Response:** The SDT has modified the R4 to not require a specific medium.<br><br>3. The MRO believes that R8 should also be revised to refer to "ATC or AFC" rather than just "ATC".<br>**Response:** These two requirements are different, and address fundamental differences between the methodologies. MOD-001 discusses the recalculation of ATC on a fixed schedule unless the components in the ATC equation change. MOD-030 R10 addresses calculation of AFC on a schedule consistent with the MOD-001 requirement. However, there is additional information in the MOD-030 requirement that is specific to that methodology. MOD-030 R10 does not require full recalculation of the distribution factors through an update of the transmission model; updates of the transmission model occur on a separate schedule as defined in MOD-030 R3. MOD-028 addresses this similarly through the recalculation of TTC on a separate schedule as defined in MOD-028 R5. MOD-029 addresses changes to topology through adjustments to TTC. Because of these technical differences between the methodologies, the SDT believes having the two requirements is appropriate. |

| Organization/Group | Question 3 - Incorrect Requirement(s) or Measure(s): |
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| | 4. The MRO believes that R5 should be revised to delete the words "all of". The phrase "all of" seems to be unnecessary and may result in over-the-top auditing.<br>**Response:** The SDT does not believe this to be an onerous requirement. Posting on a public website would accomplish this easily.<br><br>5. The MRO believes that the changes made to R6 are a significant improvement to the standard and commends the SDT on taking this more reasonable approach to consistency that is "no more limiting than those used in planning of operations."<br>**Response:** The Drafting Team appreciates this supportive comment. Note that the SDT has made other clarifying modifications to R6.<br><br>6. The MRO believes that R9 should be revised to delete the words "any" from "Within thirty calendar days of receiving a request by any Transmission Service Provider?".<br>R9 should be revised to delete the words "all" from "Unit commitments and order of dispatch, to include all designated network resources?".<br>R9 should be revised to delete the words "Any" from the phrase "Any firm and non-firm adjustments?". R9 should be revised to delete the words "Any" from the phrase "Any other services that that impact ?..".<br>R9 should be revised to delete the word "all" from "Values of CBM and TRM and TTC for all ATC [paths or Flowgates."<br>R9 should be revised to delete "any" from the phrase "any Flowgates considered by the Transmission Service Provider receiving the request?"<br>R9 should be revised to delete the word "all" from the phrase "Values of TTC and ATC for all ATC Paths for those?". These uses of "any" and "all" seem to be unnecessary and may result in over-the-top auditing.<br>**Response:** Providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of "any" and "all" prevents discretionary sets of data being provided and argued as being compliant.<br><br>7. The MRO believes comparable changes should be made to deleting "all" and "any" in the Measures, the Compliance section, and the Violations Severity Levels to match the changes to R9.<br>**Response:** Providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of "any" and "all" prevents discretionary sets of data being provided and argued as being compliant. |

| Organization/Group | Question 3 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| | 8. R3.6.3 Need to strike "that are unrecognized". The term "unrecognized" is problematic and vague.<br>**Response:** The SDT has modified the requirement to be more explicit by requiring "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed."<br>.<br>9. R3.2.2 Alternate language for the statement "a rationale for the defined accounting "A suggestion to use counterflow process instead.<br>**Response:** The SDT has modified this language to be more clear by referencing R3.2.<br><br>10. R3.3 There is a typo. Please change "of" to "or".<br>**Response:** The SDT has made the suggested correction. |
| **Response:** Please see in-line responses. | |
| Entergy Services Inc | R3.3 - Replace "---transfer of Flowgate capability." by "---transfer or Flowgate capability."<br>**Response:** The SDT has made the suggested correction.<br><br>R3.6.3 - Entergy is not sure what the parenthetical is implying, specifically the phrase, "that are unrecognized." In addition, Entergy proposes that rather than processing of outages, it should refer to modeling of outages in ATC calculations, therefore, replace "processed" by "modeled".<br>**Response:** The SDT has modified the requirement to be more explicit by requiring "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed."<br><br>R6 and R7 - The phrase "planning of operations" may be better understood if the term "reliability" was inserted at the beginning. We assume that the SDT is trying to tie the reliability planning studies/activities to the ATC calculations. Similar terms are used in MOD-030. (This also raises the question of why it is in MOD-030 and not MOD-028 and MOD-029.) If all instances can use the same phrase, we think the standards would benefit from the standardization.<br>**Response:** The drafting team carefully reviewed Order 890, and modified the language to be consistent with that used in the Order. The Order specifically refers to the "planning of operations." The SDT believes this to be a specific reference to the Operations Planning timeframe.<br><br>In MOD-030, the standard describes the specific rules for identifying flowgates. In MOD-001, the reference relates to the generic calculation of ATC/AFC and TTC/TFC, which correctly applies to all three methodologies. |

<table>
<tr><th>Organization/Group</th><th>Question 3 - Incorrect Requirement(s) or Measure(s):</th></tr>
<tr><td></td><td>R8.1 needs to be worded as requirement rather than giving allowance/exemption from the requirement for 80 hours (approx 1% of 8760 hours) in a calendar year.  Entergy recommends the language "Hourly values, once per hour at least 99% of hours every calendar year."<br>Response: The SDT believes the current language is consistent with the intent.<br><br>R9 - This requirement is for sharing the data by TSP with others who need it for calculation of their ATCs.  This requirement is not to replace the requirement of Order 889  37.6(b) (2)(ii) "On request, the Responsible Party must make all data used to calculate ATC and TTC for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (e.g., thermal, voltage, stability)) in electronic form within one week of the posting.  The information is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material."  If it can be emphasized this fact, it will greatly clarify some confusion that some stakeholders are having regarding data sharing.<br>Response: The SDT has added a yellow text box to the standard to highlight this fact.</td></tr>
<tr><td colspan="2">Response:  Please see in-line responses.</td></tr>
<tr><td>Ontario IESO</td><td>We have the following comments on specific requirements:<br>1. R3.6.3: This subrequirement is too vague and its addition is not necessary. Subrequirements R3.6.1 and R3.6.2 suffice to hold the TSP responsible for considering the impact of outages in ATC calculation. How the outages are processed has no bearing on the ultimate scenarios (topologies) that the TSP must consider.<br>Response: The SDT has modified the requirement to be more explicit by requiring “how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.”<br><br>2. We do not agree with the changes made to R6 and R7. By “no more limiting than” the assumptions used in planning of operations for the same time period, it would imply that the TOP and TSP may use less restrictive (or more liberal) assumptions. The results could be that the TTCs and ATCs are higher than the planned operational parameters, giving rise to potential unreliability. We do not see a problem with the previous wording of “consistent with”, and this should be reinstated.<br>Response: The SDT attempted to consider the intent of the Order in its review of this requirement.  It seems clear, from both a reading of the order and from comments submitted to the SDT, that FERC’s intent is to ensure that service is not sold on a more conservative basis than the system has been planned for.  Accordingly, the SDT modified this requirement to more closely align with this goal.  Additionally, it was pointed out that requiring the two to be “consistent” could lead to conflicts and double jeopardy between these standards and the planning standards.</td></tr>
</table>

| Organization/Group | Question 3 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| | If entities are concerned that this "may result in the use of less restrictive assumptions and hence give rise to potential unreliability," the SDT suggests that those entities ensure their Planning efforts utilize sufficiently conservative assumptions and use the same assumptions in their calculation of ATC. Meeting the requirements of this standard does not eliminate the responsibility to reliably operate the Transmission system in real-time. |
| **Response:** Please see in-line responses. | |
| Hydro One Networks | There are 2 methodologies listed in R1. Are these the only two from which we have to choose? We suggest rewording the requirement to avoid this confusion by inserting the words "for example". In R6 and R7, we prefer the previous wording "consistent with" instead of "no more limiting" as the new wording may result in the use of less restrictive assumptions and hence give rise to potential unreliability. |
| **Response:** The SDT has listed three choices: Area Interchange, Rated System Path, and Flowgate. These relate to three detailed standards. It is expected that Transmission Operators choose one or more of the detailed methodologies to implement. The SDT has modified R1 to be clearer.<br><br>Regarding R6 and R7, the SDT attempted to consider the intent of the Order in its review of this requirement. It seems clear, from both a reading of the order and from comments submitted to the SDT, that FERC's intent is to ensure that service is not sold on a more conservative basis than the system has been planned for. Accordingly, the SDT modified this requirement to more closely align with this goal. Additionally, it was pointed out that requiring the two to be "consistent" could lead to conflicts and double jeopardy between these standards and the planning standards.<br><br>If entities are concerned that this "may result in the use of less restrictive assumptions and hence give rise to potential unreliability," the SDT suggests that those entities ensure their Planning efforts utilize sufficiently conservative assumptions and use the same assumptions in their calculation of ATC. Meeting the requirements of this standard does not eliminate the responsibility to reliably operate the Transmission system in real-time. | |
| American Transmission Company | Modification to Requirement 1: Each Transmission Operator shall select a methodology for calculating ATC or AFC for each ATC Path or Flowgate for each time period identified in Requirements 2.1 - 2.3 for those Facilities within its Transmission Operators Area.<br>**Response:** The Reference to R2 within R1 is intended to include all components of R2, including the sub-requirements.<br><br>Modifications to 2.2Daily values for at least the next 31 calendar days (Following the 48 Hours specified in R2.1) Modification to 2.3Monthly values for at least the next 12 months (Following the 31 Calendar days specified in R2.2)<br>**Response:** The SDT disagrees with this interpretation. Entities are expected to calculate overlapping |

| Organization/Group | Question 3 - Incorrect Requirement(s) or Measure(s): |
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| | values so entities know the "daily" ATC for the next two days, as well as the hourly ATC for the next two days. The same is true for monthly and daily values.<br><br>Modification to R3:Each TSP shall prepare and keep current an ATCID that includes the following information. (The Phrase "at a minimum" is unnecessary because the TSP must comply with the sub-requirements. Any additional information is beyond the requirements and therefore not subject to NERC's audit.)<br>**Response:** The SDT drafted this language so that entities may include more information in their ATCID if they so desire and still be in compliance with the standard. The standard is not intended to require the ATCID to have only the information listed.<br><br>Starting in Requirement 3.3 the phrase "transfer or Flowgate capability" is used. Does this phase equate to ATC and AFC where ATC is equal to transfer capability and AFC is equal to Flowgate capability? We would prefer that the SDT remain consistent and use the phrase "ATC or AFC if the phrases are equal .<br>**Response:** The phases are not equal, and are intended to cover the following four values: ATC, AFC, TTC, and TFC.<br><br>In Requirement 3.3 did the SDT mean "transfer or Flowgate capability" or "transfer of Flowgate capability"? The requirement currently uses the "of" word. In order to maintain a consistent use of the phrase "ATC or AFC" we suggest the following change to Requirement 3.6. "A description of how outages are considered in ATC or AFC calculations including:" The SDT should explain any disagreement with our suggested modification.<br>**Response:** The SDT has corrected the typographical error from "of" to "or."<br><br>The phases are not equal, and are intended to cover the following four values: ATC, AFC, TTC, and TFC.<br><br>.<br>R5 should be revised to delete the words "all of" to avoid being overly inclusive.<br>**Response:** Providing only "some" of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of "any" and "all" prevents discretionary sets of data being provided and argued as being compliant.<br><br>R6 should be revised to "no more limiting than those used in the planning of operations. "<br>The SDT has modified the language as suggested. |

| Organization/Group | Question 3 - Incorrect Requirement(s) or Measure(s): |
| --- | --- |
| | Modifications to R8: The TSP shall recalculate ATC or AFC on the following frequency, unless none of the calculated values identified in the ATC or AFC equations have changed.<br>**Response:** These two requirements are different, and address fundamental differences between the methodologies. MOD-001 discusses the recalculation of ATC on a fixed schedule unless the components in the ATC equation change. MOD-030 R10 addresses calculation of AFC on a schedule consistent with the MOD-001 requirement. However, there is additional information in the MOD-030 requirement that is specific to that methodology. MOD-030 R10 does not require full recalculation of the distribution factors through an update of the transmission model; updates of the transmission model occur on a separate schedule as defined in MOD-030 R3. MOD-028 addresses this similarly through the recalculation of TTC on a separate schedule as defined in MOD-028 R5. MOD-029 addresses changes to topology through adjustments to TTC. Because of these technical differences between the methodologies, the SDT believes having the two requirements is appropriate.<br><br>Question to R8.1: How will the 80 hours per calendar year be calculated? (Does a non-calculation period that is exempt in Requirement 8 count to the 80 hours?)<br>**Response:** No. The SDT has modified R8.1 to make this clearer.<br><br>R9 should be revised to eliminate "any" and "all" to avoid being overly inclusive:<br>(1) delete the words "any" from "Within thirty calendar days of receiving a request by any Transmission Service Provider?";<br>(2) delete the words "all" from "Unit commitments and order of dispatch, to include all designated network resources?";<br>(3) delete the words "Any" from the phrase "Any firm and non-firm adjustments?";<br>(4) delete the words "Any" from the phrase "Any other services that that impact ?..";<br>(5) delete the word "all" from "Values of CBM and TRM and TTC for all ATC [paths or Flowgates.";<br>(6) delete "any" from the phrase "any Flowgates considered by the Transmission Service Provider receiving the request?";<br>(7) delete the word "all" from the phrase "Values of TTC and ATC for all ATC Paths for those?".<br>5. Delete "all" and "any" in the Measures, the Compliance section, and the Violations Severity Levels to avoid being overly inclusive.<br>**Response:** Providing only “some” of the data would not accomplish the reliability goal of sharing information transparently for the purposes of improving ATC. Use of the words of “any” and “all” prevents discretionary sets of data being provided and argued as being compliant. |
| **Response:** Please see in-line responses. | |

| Organization/Group | Question 3 - Incorrect Requirement(s) or Measure(s): |
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| New York Independent System Operator | The NYISO continues to agree with the ISO/RTO Council that the MOD standards extend into areas that should be covered and addressed by NAESB Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices, and not included in the NERC standards as reliability based requirements<br>**Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives.<br><br>Nevertheless, to the extent that the SDT decides to keep such requirements in proposed MOD-001, the NYISO offers the following additional comments or R2, R8, and M2.<br><br>R2 This requirement continues to reflect an assumption that all Transmission Service Providers are required under FERC's regulations to calculate and post ATC values for periods 48 hours, one month, and one year into the future. This is not true of the NYISO. Because of the nature of its financial reservation system, FERC has only required the NYISO to calculate and post ATCs for its internal interfaces for a period one day-ahead. The NYISO does not post and calculate, and given the nature of its system, cannot post and calculate, ATCs further out than one day ahead for those internal interfaces or for certain controllable lines that link the NYISO to neighboring Transmission Service Providers. Thus, as drafted, R2 would conflict with FERC orders and FERC approved tariff provisions excusing the NYISO from posting longer range ATCs. It would also require the NYISO to calculate and post ATCs that it cannot practically calculate given the nature of its system (under which ATC is determined primarily by the output of the NYISO's day-ahead and real-time market software). If R2 is not modified, the NYISO would have to seek a modification (or waiver) from FERC to avoid being subject to penalties for non-compliance with a requirement that should not apply to it. The NYISO respectfully requests that the SDT address the problem by revising proposed R2 as follows:"<br>Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the ATC methodology or methodologies selected by its Transmission Operator(s), except to the extent that the Transmission Service Provider is not required, under FERC?s regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]<br>R2.1. Hourly ATC values for at least the next 48 hours.<br>R2.2. Daily ATC values for at least the next 31 calendar days.<br>R2.3. Monthly ATC values for at least the next 12 months (months 2-13).<br>**Response:** It is recognized that under the financial market operated by NYISO, where the advance purchase of transmission service is not required, some of the variables in these standards may be zero at all times, and some variables may be zero for certain periods of time. However, the SDT is developing the standard to apply across all market designs, and for other areas this is more useful |

| Organization/Group | Question 3 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| | information. The Drafting Team notes that NYISO can describe their process, and which components of the ATC equation are zero in their ATCID to satisfy these standards. Based on the Drafting Team's understanding of the NYISO market, the standard can be applied to the NYISO market as-written and does not believe it is necessary to incorporate the suggested exceptions. However, NYISO may pursue an Entity or Regional variance if you feel it is necessary.<br><br>With respect to your comments on 'posting' ATCs; the NERC standards are for reliability and do not address 'posting' of any data, all posting requirements are handled by NAESB.<br><br>With respect to the suggested language to be added to the requirement; these standards are applicable to all of North America, and every effort is made to avoid references to FERC regulations, orders and Tariffs because not all entities that must comply with NERC standards are FERC jurisdictional.<br><br>In addition, the violation severity levels for these draft standards now have a graded implementation. Nevertheless, it may still be possible for multiple violations to result from a single unintended event. The NYISO requests that double counting of violations for a single event be eliminated by adding a new Item 6 to Section A of the proposed standard to establish this point.<br>**Response:** The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events.<br><br>R8 The NYISO has previously asked the SDT to clarify or revise R8 so that Transmission Service Providers such as the NYISO that are not required to post monthly ATC values for internal interfaces (See the NYISO's response to Question One, above) would not be subject to a requirement to recalculate such values on a weekly basis. Otherwise, R8 would effectively require the NYISO to conduct calculations that FERC has excused it from conducting and that would serve no reliability purpose under the NYISO's financial reservation transmission model. The NYISO therefore respectfully requests that the SDT revise R8 to clearly establish that Transmission Service Providers need not recalculate ATC values that they are not required to calculate or post under FERC's regulations, or as a result of FERC orders M2 Consistent with the NYISO's comments on R2 and R8, and with past NYISO comments, NERC should revise M2 to clearly state that Transmission Service Providers need not provide evidence that they calculated ATCs that they are not required to calculate or post under FERC's regulations, or as a result of FERC orders<br>**Response:** There are several different issues to respond to in this comment:<br>• With respect to the NYISO comment on posting, R8 does not require any posting of |

| Organization/Group | Question 3 - Incorrect Requirement(s) or Measure(s): |
|---|---|
| | information, the NERC standard deals solely with the calculation of information.<br>• As describe in Q1, the internal interfaces for which NYISO calculates ATC do not seem to fall under the definition of an ATC Path; therefore these NERC standards would not apply to what NYISO is currently calculating on those internal interfaces.<br>• With respect to the suggested language to be added to the requirement; these standards are applicable to all of North America, and every effort is made to avoid references to FERC regulations, orders and Tariffs because not all entities that must comply with NERC standards are FERC jurisdictional. |
| **Response:** Please see in-line responses. | |
| Bonneville Power Administration | BPA does not believe any are incorrect. |

4. The drafting team has modified the Violation Risk Factors for MOD-001 to reflect industry concerns that they did not reflect NERC's VRF definitions. NERC's VRF definitions are listed below. If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification. Are the current VRFs established correctly?

High Risk Requirement:

(a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement:

(a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or

(b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement: is administrative in nature and

(a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or

(b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

**Summary Consideration:**

All entities that responded indicated support for the new VRFs.

| **Organization/Group** | Question 4: | Question 4 Comments: |
|---|---|---|
| EPSA | | no comment |
| ISO RTO Council/Standards Review Committee (SRC) | Yes | The MOD standards assess the correct amount of reliability risk in areas that do not affect reliability. The IRC supports the position that no requirement from this set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the |

| Organization/Group | Question 4: | Question 4 Comments: |
|---|---|---|
| | | preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. |
| **Response**: The SDT disagrees that these areas do not affect reliability, but are appreciative of the supportive comment. | | |
| PJM | Yes | PJM supports NERC's position to revise all Violation Risk Factors to have an assigned risk factor of "Lower." A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. |
| **Response:** Thank you for this supportive comment. | | |
| FirstEnergy | Yes | FE supports the SDT's adjustment of VRFs such that no VRF within the ATC standards exceeds a "Lower" rating. We concur with the team's reasoning and rationale provided in response to ballot comments in making this change. |
| **Response:** Thank you for this supportive comment. | | |
| MRO NERC Standards Review Subcommittee | Yes | The MRO commends the SDT in the changes made to VRFs to Lower. The MRO agrees that these changes put the VRFs more in line with the NERC's definitions of the VRF levels. |
| **Response:** Thank you for this supportive comment. | | |
| American Public Power Association | Yes | |
| SERC Available Transfer Capability Working Group (ATCWG) | Yes | |
| The Midwest ISO | Yes | |
| Transmission Agency of Northern California | Yes | |
| WECC Market Interface Committee / Sub Commtt / ATC Task Force | Yes | |
| Southwest Power Pool | Yes | |
| Manitoba Hydro | Yes | |
| Public Service Commission of South Carolina | Yes | |
| Orlando Utilities Commission | Yes | |

| **Organization/Group** | Question 4: | Question 4 Comments: |
|---|---|---|
| NPCC Regional Standards Committee | Yes | |
| Duke Energy Corporation | Yes | |
| Oncor Electric Delivery | Yes | |
| Bonneville Power Administration | Yes | |
| Xcel Energy | Yes | |
| Gainesville Regional Utilities | Yes | |
| Entergy Services Inc | Yes | |
| Ontario IESO | Yes | |
| Hydro One Networks | Yes | |
| American Transmission Company | Yes | |
| Texas-New Mexico Power Company | Yes | |
| New York Independent System Operator | Yes | |

5. The drafting team has modified the Violation Severity Levels for MOD-001 to reflect industry concerns that they were too "pass/fail" oriented and to reflect the modifications to the requirements and measures. Are the current VSLs established correctly?

**Summary Consideration:**

Some entities suggested R8 in MOD-001 and R10 in MOD-030 needed to be aligned. The SDT modified MOD-030 to address this.

Some entities identified an overlap in the VSL for R3. The SDT corrected the overlap.

Some entities requested that the standard include a statement that a single event could not create multiple violations. The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events.

| Organization/Group | Question 5: | Question 5 Comments: |
|---|---|---|
| EPSA | | NO COMMENT |
| The Midwest ISO | No | The VSLs for R8 of MOD-001 are inconsistent to the VSLs stated for R10 of MOD-030 although each is related to comparable requirements regarding the frequency of recalculations. If the suggestion of deletion of R10 in MOD-030 is accepted the inconsistency will be addressed. Otherwise, the team should align these VSLs consistently. |
| **Response:** The SDT has modified MOD-030 R10 to incorporate an allowance for missed calculations consistent with MOD-001 R8. | | |
| ISO RTO Council/Standards Review Committee (SRC) | No | ERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but the IRC has a concern regarding the possibility of multiple violations resulting from a single event. The IRC requests that double counting of violations for a single event be eliminated. The IRC recommends that the SDT add a new item 6 to section A of MOD-001 that states "A single event shall not result in multiple violations". A review of MOD-001 R2 and R8 should be performed for determination of multiple violations resulting from one event. |
| **Response:** The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events. | | |
| PJM | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations - this language to be added to the standard. Add a new item 6 to section A of MOD-001. For example a review of MOD-001 R2 and R8 and MOD-30 R10 should be performed for determination of multiple violations resulting from one event. |
| **Response:** The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon | | |

| Organization/Group | Question 5: | Question 5 Comments: |
|---|---|---|
| compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events. | | |
| NPCC Regional Standards Committee | No | NPCC Participating Members have the following comments on the VSL:<br>1. R3: There is a potential overlap between High and Severe. For an ATCID does not include - two or more? of the information items in R3, it could mean does not include all of the information items. This is the same condition as a Severe. We suggest to reword the High VSL to - does not include up to 2 of the information items in R3; and the Severe VSL to ?or its ATCID does not include 3 or more of the information described in R3?, or numbers along that line.<br>**Response:** The SDT has modified the standard as suggested.<br><br>2. We do not agree with the VSLs for R6 and R7 for reasons noted under Q3, above.<br>**Response:** Please see response to Q3. |
| **Response:** Please see in-line responses. | | |
| FirstEnergy | No | The VSLs for R8 of MOD-001 are inconsistent to the VSLs stated for R10 of MOD-030 although each are related to comparable requirements regarding the frequency of recalculations. If the above suggestion revising MOD-001 R8 and deletion of R10 in MOD-030 is accepted the inconsistency will be addressed. Otherwise, the team should align these VSLs consistently. |
| **Response:** The SDT has modified MOD-030 R10 to incorporate an allowance for missed calculations consistent with MOD-001 R8. | | |
| Ontario IESO | No | We have the following comments on the VSL: 1. R3: There is a potential overlap between High and Severe. For an ATCID does not include “two or more” of the information items in R3, it could mean does not include all of the information items. This is the same condition as a Severe. We suggest to reword the High VSL to ?does not include up to 2 of the information items in R3?; and the Severe VSL to ?or its ATCID does not include 3 or more of the information described in R3?, or numbers along that line.<br>**Response:** The SDT has modified the standard as suggested.<br><br>2. We do not agree with the VSLs for R6 and R7 for reasons noted above.<br>**Response:** Please see response to Q3. |
| **Response:** Please see in-line responses. | | |
| Hydro One Networks | No | For the severe VSL for R2 keep consistent the wording as per the other levels.<br>**Response:** The SDT has modified the language to be consistent.<br><br>The Lower, Moderate, and High VSLs for R4 are missing the words "did not".<br>**Response:** The SDT has modified the language as to clarify the intent. |

| Organization/Group | Question 5: | Question 5 Comments: |
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| **Response:** Please see in-line responses. | | |
| New York Independent System Operator | No | The NYISO agrees with the ISO/RTO Council comments on this issue. NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now for the most part have a graded implementation, but the NYISO remains concerned regarding the possibility of multiple violations resulting from a single event. Therefore, the NYISO requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. |
| **Response:** The SDT does not believe it is within the drafting team's scope to modify the standards template or create obligations upon compliance. In response, the drafting team has clarified many of the Violation Severity levels in an attempt to eliminate the potential for multiple violations due to single events. | | |
| American Public Power Association | Yes | |
| Transmission Agency of Northern California | Yes | |
| WECC Market Interface Committee / Sub Commtt / ATC Task Force | Yes | |
| Manitoba Hydro | Yes | |
| Public Service Commission of South Carolina | Yes | |
| Orlando Utilities Commission | Yes | |
| Duke Energy Corporation | Yes | |
| Oncor Electric Delivery | Yes | |
| Bonneville Power Administration | Yes | |
| Xcel Energy | Yes | |
| Gainesville Regional Utilities | Yes | |

| Organization/Group | Question 5: | Question 5 Comments: |
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| MRO NERC Standards Review Subcommittee | Yes | |
| Entergy Services Inc | Yes | |
| American Transmission Company | Yes | |
| Texas-New Mexico Power Company | Yes | |

6. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-001**.

**Summary Consideration:**

Several entities expressed concern with ERCOT's applicability. The drafting team explained the applicability of the standard, and suggested that ERCOT may wish to pursue a regional standard or variance.

It was suggested that more detail needs to be developed for the treatment of counterflows. The SDT suggested the commenter develop a SAR in pursuit of this detail.

The NERC RTOSDT expressed concern that the standard does not refer to planning and operating limits. The SDT directed the RTOSDT to the specific areas in the methodology standard where such references are made.

Some entities expressed concern with the effective date and the "concurrent" implementation being dependent on "all" regulatory authorities. The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals.

The drafting team provided a summary of the use of time horizons to address some comments.

Some entities suggested that the allowance for a certain number of hourly calculations to be skipped did not specify that the allowance was only for software outages. The SDT felt that qualifying the limit as suggested would be difficult to verify objectively, as software outages vary in degree and impact.

| Organization/Group | Question 6 Comments: |
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| American Public Power Association | Excellent work - my thanks to the SDT members. |
| **Response:** Thank you for your supportive comment. | |
| CenterPoint Energy | The group of standards is for ATC and TRM methodologies that are not used in ERCOT. CenterPoint Energy is concerned that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these standards, which we believe would not add value to the ERCOT region and could increase congestion in the region. Accordingly, CenterPoint Energy previously submitted comments to these standards asking for an exemption for the ERCOT region. We find the proposed standards unacceptable unless the following provision is added to each standard: This standard does not apply to ERCOT or any other region that operates as a single control area. |
| **Response:** MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that | |

| Organization/Group | Question 6 Comments: |
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| states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| Transmission Agency of Northern California | R.9 lists many data elements that another entity can request and a TSP is obligated to provide. Not all TSPs have or use this data themselves, and R.9 should be clarified to state that the TSP is not obligated to provide data it does not have. Perhaps this is implied in R9.1, but if so it should be stated more clearly.<br><br>Also the first sentence of R.9 is ambiguous - I assume the requested data is for use in the requestor's ATC or AFC calculations, but it could also be read that the data is used in the ATC/AFC calculation of the TSP receiving the request. |
| **Response:** The SDT has clarified the language to explain the intent. | |
| Southwest Power Pool | R3.6.3. How outages (including those outages from other Transmission Service Providers that are unrecognized) are processed. Define "unrecognized." Does this also refer to outages that are not used because the elements are well outside the TSP's model and therefore do not impact calculations?<br>**Response:** The SDT has modified the requirement to be more explicit by requiring "how outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed."<br><br>R9. Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below for use in ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2:The concern of R9 is numerous requests that could create an unnecessary burden for TSPs fulfilling said requests. SPP feels a justification should be provided with requests to promote communication between requestor and TSP so desired result is obtained.<br>**Response:** The methodology standards themselves (MOD-029, -029, and -030) define the required uses of neighbors information in the ATC process. It is expected that the TSP will be required to respond to neighbors needs for information as those neighbors comply with the standards. Similarly, it is expected that the TSP will be requesting this data from its neighbors. |
| **Response:** Please see in-line responses. | |
| EPSA | We offer two additional comments. First, with respect to the purpose of this standard, we believe the purpose of the previous draft was more appropriate. The previous draft stated that consistency in the calculation of ATC and appropriate documentation were part of the purpose of this standard. We believe those are important purposes and should be included. |

| Organization/Group | Question 6 Comments: |
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| | **Response:** The SDT drafted the purpose to align more closely with the reliability objectives of the standard. While consistency and documentation are also important components of the standard, they support the reliability objectives included in the purpose, and are not in themselves the purpose for the standard.<br><br>Secondly, requirement 3.2 dealing with counterflows is insufficient in the current draft. We accept that consistency in the use of counterflows on all interfaces would not be appropriate. Indeed it is likely that even within a single system, it is likely appropriate that the counterflows on some interfaces be treated differently than others based on historical usage of the interface. However, to create a standard that requires only an identification of the methodology and a statement of the rationale, with no guidance on appropriate methodologies or acceptable rationales is not sufficiently enforceable and amounts to a fill-in-the-blank standard.<br>**Response:** The SDT discussed counterflows extensively during previous drafting efforts. The current language is intended to ensure that the treatment of counterflows is understood for coordination purposes. With regard to specific methodologies or acceptable rationales, the SDT encourages EPSA to draft a SAR that identifies suggestions for improving the manner in which counterflows are addressed in the standard. |
| **Response:** Please see in-line responses. | |
| ISO RTO Council/Standards Review Committee (SRC) | The IRC applauds the efforts of the NERC Standards Drafting Team (SDT) in providing a set of MOD standards for formal comment that include many of the Industry's comments from the Ballot. However, there are several standards which still require modification. The MOD standards extend into areas that should be covered and addressed by NAESB Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices, and not included in the NERC Standards as reliability based requirements (see specific details for MOD-001 R2 and R7). Non-firm should be removed from this reliability standard. |
| **Response:** The SDT appreciates the supportive comment.<br><br>The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives. Removal of non-firm from the standard could allow for unchecked selling of non-firm service, which could lead to concerns within real-time. | |
| ERCOT ISO | I suggest modifying the Applicability section to state:4.1 Transmission Service Provider with ATC Path(s)<br>4.2 Transmission Operator with ATC Path(s)<br>**Response:** The SDT does not agree. Entities without ATC paths, while not required to implement one of the three ATC methodologies, are still required to implement other portions of the standard, including the requirement to support the Data Exchange if requested.<br><br>Comment: It is unclear how failing to meet the requirements of MOD-001 affects grid reliability. This should be a commercial standard or a business practice rather than a reliability standard requirement.<br>**Response:** FERC identified in Order 890 that this “Predictable, sufficiently accurate, consistent, equivalent, and replicable |

| Organization/Group | Question 6 Comments: |
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| | results promote reliability." The drafting team concurs.<br><br>Assuming that ERCOT has no ATC Paths, the remaining requirements support reliability in that they provide coordination information to entities impacted by ERCOT operations. This includes entities both internal and external to ERCOT.<br><br>Severity Levels: Violation of timing requirements should not constitute a severe violation. A severe violation is the failure to attempt to perform the task at all. A high violation could be a long failure to perform, such as >96 hours with NO attempted corrective action. All other failures in timing should be lower violation severity.<br>**Response:** A severe violation is not a failure to attempt to perform the task at all, it is a complete violation or a mostly complete violation of the requirement. While consideration of intent may be undertaken by an auditor when determining sanctions, the verification of whether the violation occurred or not is an objective determination regardless of intent. |
| **Response:** Please see in-line responses. | |
| Orlando Utilities Commission | Overall Question: As written currently, the standard appears to set requirements for calculating TTC/TFC/ATC/AFC etc, but does not require an entity to perform the calculation. For example, R1 and R6 apply to the TOP, but as written if the TOP doesn't calculate ATC/AFC/TTC/TFC then nothing in the requirements seems to obligate them to do so. This also seems to be true of the requirements that apply to a TSP. Is this a correct reading of the requirements?<br>**Response:** R1 requires that if an Transmission Operator has "ATC paths," they must choose a methodology. R2 requires the Transmission Service Provider to use that methodology. To the extent an Transmission Operator has no ATC paths, the associated Transmission Service Provider would not be obligated to calculate ATC/TTC/TFC/AFC.<br><br>Requirement 6: If the drafting team changes the responsible entity in Requirement 1, will they also change this one?<br>**Response:** No. The Transmission Operator remains responsible for determining TTC and/or TFC.<br><br>Requirement 6 & 7: What if there is not "planning of operations" activity for the corresponding time period? For example while month 11 may have an ATC study done, it may not have a corresponding "planning of operations" activity.<br>**Response:** The SDT has modified the requirement to clarify that if a study has not been undertaken for a specific period, there is no requirement for the assumptions to be no more limiting than those used in the study.<br><br>Requirement 6 & 7: Could you provide some examples of what you mean by "assumptions."<br>**Response:** The SDT has provided several examples within the measures for the requirement<br><br>Requirement 6 & 7: What is the reliability purpose of these requirements, specifically what is the reliability purpose of setting a maximum threshold on how limiting an assumption can be?<br>**Response:** FERC identified in Order 890 that this "Predictable, sufficiently accurate, consistent, equivalent, and replicable |

| Organization/Group | Question 6 Comments: |
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| | results promote reliability." The drafting team concurs. |
| **Response:** Please see in-line responses. | |
| PJM | Depth of the ATC MOD standards extends beyond the scope of the reliability standards The MOD standards extend into areas that should be covered and addressed by NAESB Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices, and not included in the NERC Standards as reliability based requirements (see specific details for MOD-001 R2 and R7 and MOD-030 R10 in the Specific Comments sections below). Non-firm should be removed from this reliability standard. |
| **Response:** The SDT believes that creating a requirement to perform an action in a certain way without associated requirements that an entity actually perform the action would not meet any reliability objectives. Removal of non-firm from the standard could allow for unchecked selling of non-firm service, which could lead to concerns within real-time. | |
| Electric Service Delivery | These comments are filed on behalf of City of Austin d/b/a Austin Energy to address proposed NERC 5 MOD Standards. Austin Energy is a municipally owned electric utility and a transmission service provider with the Electric Reliability Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with no explicit transmission services being sold. Current ERCOT market rules allow open transmission access to all loads and resources. ERCOT will continue to operate as a Single Balancing Authority under Nodal market design. Accordingly, as explained in more detail below, the NERC 5 MOD Standards should not be applied to ERCOT and transmission service providers within ERCOT under its current or proposed Nodal market design. Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations.<br>Applicable definitions:According to NERC Reliability Standards Glossary of Terms, Available Transfer Capability (ATC) is defined as: ?A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability (TTC) less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows?.<br>TTC is defined as: the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions.<br>CBM is defined as the amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.<br>TRM also is a component of ATC defined as: that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.<br>Comments:ERCOT is an interconnection and a region with no synchronous AC ties with any other interconnections. In July 2001, based on a deregulated Retail and restructured Wholesale Markets, the ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT market is designed such that there are no explicit transmission services being sold, hence, Available Transfer Capability (ATC) is not a measure used in a commercial activity within the ERCOT market. The current ERCOT market rules allow open transmission access to all eligible loads and resources without considering any specific Transmission Service Provider (TSP). Transmission facilities ratings are based upon individual branch element |

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| | designs and in cases of dynamic ratings, ambient conditions are also considered. ERCOT has several DC ties and an asynchronous tie using a Variable Frequency Transformer (VFT); however, the associated interchange capabilities are planned and coordinated by the TSPs involved. The current ERCOT Zonal Market uses a flow based congestion management methodology to predict potential congestions in the Day Ahead and Adjustment Periods. During the operating period, generation shift factors are used to determine the dispatch needed to remain within the constrained limits. The local congestions are managed using full AC load flow analysis and unit specific redispatch.MOD-001-1 is entirely about methodology and calculation of ATC, therefore, this standard is not applicable to ERCOT.<br>MOD-008-1 covers Transmission Reliability Margin (TRM) methodology calculation. Mathematically, ATC is defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin (CBM). Therefore, TRM also is not applicable to ERCOT.<br>MOD-028-1 covers Area Interchange calculation Methodology. Since ERCOT is a single control area, Area Interchange calculation is not applicable.<br>MOD-029-1 covers Rated System Path Methodology, which is used to calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT.<br>MOD-030-1 covers Flowgate methodology calculation of ATC, and therefore, is not applicable to ERCOT.<br>ERCOT is currently transitioning to a Nodal Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a Security Constrained Economic Dispatch (SCED) approach to dispatch individual generating units and manage congestion. In the Nodal Market, ERCOT will still operate as a Single Balancing Authority. This again will not use ATC methodology, and aforementioned standards are not applicable to ERCOT in its ensuing Nodal Market.Therefore, Austin Energy requests that the NERC Standards Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority that do not use ATC methodology and any of its components in their market operations. |

**Response:** MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part.

Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT beleives that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)*

| Organization/Group | Question 6 Comments: |
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| California ISO | Purpose ? The MOD 1 Purpose as presently written does not clearly relate the intent of the associated MOD standards. Purpose statement should be more explicit, i.e. ?To require that ATC calculations are performed by TSPs for present (DA and HA) and forecasted system operating conditions on ATC Paths?, using one or more of the 3 ATC calculations options embodied in MOD 28 ? 30. Purpose should clearly state ?for ATC Paths?, and then clearly define ?ATC Paths?.<br>**Response:** The Purpose is intended to be a high-level summary of the goals of the standard, and not serve as a requirement or applicability statement. The qualification related to "ATC Paths" is included in R1.<br><br>The present MOD 1 CFR definition of ?ATC Path? is very open to interpretation, given that ?ATC Path? is defined first as a ?Posted Path? via a footnote reference to 18 CFR 37.6(b)(1) OR ?any OTHER combination of POR and POD for which ATC is calculated?. Posted Path implies a requirement to post the ATC to an OASIS site, and to Market the transmission on the referenced path. The MOD 1 ?ATC? definition does refer to the intention that ATC is calculated ?for further commercial activity?. Presumption is that the ATC is posted for sale. ATC Path Definition ? Clarify that ATC Path definition is applicable ONLY to interties and internal paths between systems where Transmission is sold (for further commercial activity).<br>**Response:** The SDT has modified the definition of ATC Path to be clearer by moving the "Other combination" phrase, and believes that as written, it specifies what qualifies as a path for which ATC or AFC must be calculated.<br><br>Clarify if ANY posting requirement is embodied in these standards. Explanation ?<br>**Response:** NERC is not specifically requiring any posting of information. However, the SDT notes that in some cases, it may be possible to meet a requirement through posting of information. For example, when the STD requires information to be "made available" to certain entities, this can be accomplished in many ways, only one of which would be posting of the data.<br><br>It is the California ISO?s interpretation is that under MOD 1 and 29, the ISO will be required to calculate and post ATCs for each of its 41 interties. The ISO will use the MOD 29 Rated System Path Methodology to calculate ATCs DA, HA and for future Market timeframes, consistent with practice in the WECC for interchange ratings. However, the ISO will be employing a Flow based Integrated forward Market under its new MRTU Market design to be implemented this Fall. This internal ISO Market will use an Integrated Forward Market in combination with an Full Network Model and LMP pricing to dispatch generation, imports and exports, procure AS and Balancing energy for RT, to optimize use of the grid. This model employs the use of flowgates in the 3000 node FNM. However, the ISO will only be posting ATCs for transmission capability at the 41 ties, consistent with our Market design and interpretation of the definition of ATC Path, provided by these proposed ATC standards.<br>Note; The CAISO operates the combined transmission assets of 11 TOs located within its BAA boundary, as one Transmission system for Market purposes. Is this interpretation consistent with the SDT?s intent? Does the SDT believe that MOD 30 contains any requirement to convert the IFM's use of flow gates to ATCs, given that these AFCs are not related to ATC Paths, as defined by MOD 1? This would appear to be very impractical and of virtually no Market benefit, as the power flow solution used to dispatch energy in the IFM is only known after the IFM has run, and a power flow solution is reached for each of the thousands of interconnected transmission elements within the BAA for the 3000 nodal bus network. |

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| | **Response:** The SDT does not believe any conversion from AFC to ATC is required by these standards.<br><br>R2 & R8 ? Should the actual ATC Calculation timing requirements to relegated to a NAESBY Standard??? Any requirement to calculate and post ATC with any accuracy, should be limited to the Hourly, daily and perhaps weekly values. The requirement to calculate Monthly and yearly ATC values beyond the outage reporting requirements and beyond any reasonable expectation of knowledge of operating conditions, is of minimal use, under and CAISO Market construct. Posting of ATC for timeframes beyond seven days would seem to be very inaccurate, not knowing what the operationally constraints would be to any degree of accuracy (I.e. hydro conditions, forced outages, planned generation and transmission outages, planned maintenance work).<br>**Response:** The SDT acknowledges for a market, this info may not be as useful, and in many cases, components used in the ATC equation may be zero for a market. However, the SDT is developing the standard to apply across all market designs, and for other areas, this is more useful information. In some cases, the pursuit of Entity or Regional Variances may be appropriate.<br><br>R9 - Does this Requirement require that the CAISO release our power flow model to our TO?s, absent a NDA??? See 9th bullet.<br>**Response:** The SDT notes that R9.1 subjects the obligation to provide the model to security and confidentiality requirements. To the extent such requirements mandate the execution of a non-disclosure agreement, the SDT does not believe that requiring an NDA is in conflict with the standard. |
| **Response:** Please see in-line responses. | |
| NERC RTOSDT | The Real Time Operation Standards Drafting Team is concerned that the proposed MOD standards do not include any reference to the Planning and Operating Limits mandated by the current FAC, IRO and TOP standards. These standards already include transmission flow limits both in the longer term planning time frame as well as the shorter term operating time frame. The proposed MOD standards seem to be establishing procedures to calculate the commercial boundaries without a direct link to the required reliability boundaries.<br>MOD-001 R6 states that the TTC ?use assumptions? no more limiting than those used in planning. The RTO SDT would ask shouldn?t TTC?s be required to be ?no less limiting? than the SOLs / IROLs computed for the system? Current NERC standards are not just asset limits, they are also system limits. The current standards require that limits be calculated that recognize both local and wide-area impacts. The RTO SDT believes that by at least linking (if not entirely eliminating) the MOD standards to the current SOLs / IROLs requirements, the Industry would be more correctly linking how the system MUST BE operated to any NAESB business practice. Indeed it would seem that current tariffs are based on the computations used in current planning and operating environments. By using the current SOL / IROL limits the procedural / prescriptive requirement in MOD-001 R9 et al would be unnecessary (i.e. they would revert back to the FAC and IRO requirements)The questions for the ATC SDT:? How do these MOD standards relate to the SOLs / IROLs? Why should these ATC/TTC limits be decoupled from the SOLs / IROLs? Shouldn't the long-term SOL / IROL limits computed in Planning be the TTC for the system (or at least the basis for the TTC)? Shouldn't the short-term SOL / IROL be the basis for the ATC for the system? MOD-008 computes margins. By coordinating the MOD standards with the SOL / IROL standards, the only |

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| | Business (not NERC) requirement may be to define the options on how the TSP could couple the various SOL / IROL values that it obtains from its RCs and TOPs. MOD-028By using SOLs / IROLs there would be no need to get into ATC / AFC “methodologies”. Indeed standards that include “alternatives” are not defining a single ?standard approach?. But by using specific planning and operating limits the methodologies become irrelevant. The “limit” becomes explicit and well-defined. Any margins or variations about those limits would then be obvious and transparent. What is most important is respecting the reliability-based limits and not how the commercial value is computed. If this idea of using SOLs / IROLs as the limit(s) or at least the basis for those commercial limits, then the TSP becomes a coordinator of which values to use for the commercial periods. The TSP would not be the computer of those limits. Thus MOD-028 could become a business practice for posting - rather then a standard for computations. |
| **Response:** While not included in MOD-001, the other posted methodology standards include references to SOLs to address the concerns expressed by the RTOSDT. These references are as follows: MOD-028 R6.1; MOD-029 R3; MOD-030 R2.4. Regarding the need for these standards, the approval of the SAR related to these standards and the NOPR process for Order 890 has already identified that the industry believes these methodologies are appropriate areas for standards development. | |
| NPCC Regional Standards Committee | NPCC Participating Members do not see the role of TOP in this standard. The TOP’s primary responsibility is to operate its transmission operating area in a reliable manner, and determine SOLs and where necessary, transmission transfer capabilities and flowgate capabilities (where applicable). Given the established SOLs, TTCs, TFCs that are determined by the TOP for operational planning, and the TTCs and TFCs determined by other entities such as the RCs, TPs and PCs for wider area and for different time frames, the TSP needs only to calculate ATCs (or AFCs) respecting these established constraints. In doing so, it should be able to select an ATC calculation method to suit its business model and needs, with due consideration to the basis of the TTCs and TFCs that affect its service area. With this in mind, we suggest in our response to Q2, above, that the TSP be the one who selects the ATC method and R1 should be revised accordingly.<br>Note also that it should not be assumed that the TOP area and the TSP area are the same and hence the basis of the TTCs and TFCs that affect the TSP/s area may differ from one part to another.Also we believe the TSP should be the entity to select the method to be used in calculating available transmission transfer capability since it is the entity responsible for processing transmission services, not the TOP. In determining ATCs, the TSP needs to observe SOLs, IROLs and TTCs determined by the TOPs, RCs, TPs and PCs. Keeping the determination of TTCs (TFCs) separate from the determination of ATC, including the latter’s methodology, would be the appropriate approach in moving forward with these MOD standards. |
| **Response:** Please see summary response to Question 2. | |
| FirstEnergy | FirstEnergy appreciates the Standard Drafting Team's decision to move to a formal comment period based on the prior initial ballot feedback. We commend the team for moving quickly to respond to the ballot comments and providing the industry a revised set of standards to review and comment.<br>Response: Thank you for your supportive comment.<br><br>Regarding the revision to the Effective Date, while FirstEnergy agrees that there is a need to ensure that the standard is implemented consistently across the entire continent we are concerned with the Effective Date being subject to approval of ALL regulatory authorities. We believe an appropriate Implementation Plan should reflect a period of time beyond the NERC |

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| | Board of Trustee approval date that would reflect when the requirements are considered mandatory and enforceable. The timeline should allow sufficient time for regulatory authority reviews, with the intent of sanctions also being enforced in conjunction with the conclusion of the implementation period. However, a delay from a given regulatory agency should not impact when the requirements are considered mandatory and enforceable for the bulk electric system. |
| **Response:** The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals. | |
| AEP | The Applicability of this Standard should be solely upon the TSP, the Transmission Operator should not be subject to this Standard. From the previous set of responses, it is the apparent belief of the SDT that the calculation of ATC is needed for reliability (response to AECI for example). We disagree. Considering that ATC is a mathematical amalgamation of forecasted system conditions (load, outages, generation dispatch, others? transactions, etc) compounded and adjusted by margins (TRM and CBM of own entity and other systems), using the calculated ATC to assess real or near real time transmission reliability would be ? at best ? unwise. Transmission Reliability can be assessed by monitoring specific and individual Facility loadings and/or other parameters, for example. The calculation of ATC and the value of resultant ATC is exactly for the purpose stated in the definition of ATC: ?A measure of ? capability?.for further commercial activity? ? and note the definition does not infer ATC is a measure of reliability. Granted, ATC is calculated FROM reliability derived values and concepts (such as ratings, contingency analysis aspects, SOLs etc), BUT the resultant ATC values are not an assessment of transmission reliability ? and therefore not a function for the Transmission Operators, but rather the Transmission Service Provider. |
| **Response:** Please see summary response to Question 2. | |
| PPL Supply Group | PPL suggests that the standard should require that the TSP make available the new ATC as soon as possible. |
| **Response:** While the SDT understands and supports the intent of this request, such a requirement is ultimately one that is difficult, if not impossible, to measure objectively. | |
| Oncor Electric Delivery | This standard should not apply to ERCOT for the reason expressed in question 1. |
| **Response:** MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, | |

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| and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| Bonneville Power Administration | BPA thanks the drafting team for the modifying MOD-001 to not require the conversion of AFC to ATC and agrees with your assessment that there is no reliability need for such conversion.<br>**Response:** Thank you for your supportive comment.<br><br>Additionally, BPA respectfully submits the following observations and suggestions: a. The purpose statement of MOD-001 be modified as follows to comply with FERC Order 890-A:Purpose: To ensure the consistent and transparent application and documentation for the variables defined and used in the calculation of Available Transfer Capability (ATC) or Available Flowgate Capability (AFC).<br>**Response:** The SDT removed the statement related to transparency, as this issue is not one that impacts Reliability but rather Open Access. As such, NAESB will be addressing it within their standards.<br><br>b. The Time Horizons listed for all requirements should include the "Long-term Planning" Horizon, as ATC or AFC is to be calculated beyond the seasonal window.<br>**Response:** The use of "Time Horizons" in this standard is in the form of a compliance element, and refers to the manner in which compliance evaluates the implications of a violation of the standard. In this context, time horizon has to do with the urgency of addressing a violation, e.g., how quickly a violation needs to be rectified. Together, the Violation Risk Factor and Time Horizon aid a compliance auditor in determining sanctions. Accordingly, the SDT believes that the appropriate horizon for compliances does not include "Long-term Planning."<br><br>c. Balancing Authorities may be appropriately identified as Applicable Entities in this standard and request that the Standards Drafting Team provide an explanation as to why they are not listed.<br>**Response:** The SDT is uncertain what tasks BPA would assign to the Balancing Authority. To the extent that BPA has suggested requirements or tasks for the BAs to perform, the SDT suggests that BPA draft a SAR to incorporate those requirements in a future revision to the standard. |
| **Response:** Please see in-line responses. | |
| Xcel Energy | We feel that the applicability of this standard as proposed is problematic. We also do not feel that this problematic nature is resolved by choosing either the TOP or TSP. While it is not a perfect solution, we feel the best option is for the applicability to remain at the regional level. We suggest the following wording: "Regional Reliability Organization, through its members". |
| **Response:** NERC standards have to be applicable to a functional entity, and cannot create a requirement that applies to an RRO. However, if desired, regions can create regional standards or pursue regional variances. | |
| Gainesville Regional Utilities | None at this time. |

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| MRO NERC Standards Review Subcommittee | 1. The MRO commends the SDT in making significant changes to this standard and reissuing it for comment. The MRO believes the eventual standard that is approved will serve the industry and customers better as a result.<br>**Response:** Thank you for your supportive comment.<br><br>2. The MRO believes that the first time you use an abbreviation or acronym, you must spell out the full term followed by the abbreviation or acronym in brackets. Subsequent use of the term is then made by its abbreviation or acronym. ex: "Each Transmission Operator shall select one Available Transfer Capability (ATC) methodology2 for calculating ATC (Area Interchange methodology, Rated System Path methodology) or Available Flowgate Capacity (AFC) (Flowgate methodology) for each ATC Path per time period identified in R2 for those Facilities within its Transmission Operator Area."<br>**Response:** The SDT has made the suggested modifications.<br><br>R3.3 - last line should read: “calculating ATC or AFC.<br>**Response:** The SDT has modified R3.3 to include flowgate capability, but has also clarified that since this applies to the Transmission Service provider, it only refers to “Available” capacity (since the Transmission operator is the entity that calculates Total Transfer/Flowgate Capability).<br><br>R3.4“ last line should read: ?calculating ATC or AFC.<br>**Response:** The SDT has drafted R3.4 to refer to ATC, AFC, TTC, and TFC, and believe the language used is appropriate.<br><br>R3.5 ? Each bullet should read: -allocate ATC or AFC?<br>**Response:** The SDT has drafted R3.5 to refer to ATC, AFC, TTC, and TFC, and believe the language used is appropriate.<br><br>R6 and R7 ? Overall, both requirements as written are unclear. The MRO asks that the standards drafting team specify what assumptions are referenced or else delete these requirements. Also the MRO objects the requirement to use assumptions that are no more limiting in that such a requirement would result in potentially onerous calculations to determine assumptions that meet this limitation. The MRO notes that these requirements are covered by FERC order #890 anyway.<br>**Response:** The assumptions are generally those defined in the ATC methodologies (MOD-028, MOD-029, and MOD-030). To the extent other assumptions used in the ATC processes are described in the ATCID, they should be considered as well.<br><br>R9 - Please expand/clarify the intentions of the 4th bullet. What specific aggregated firm capacity is being referenced? Capacity in ETC for each flowgate as specified by reservations? An example would be very beneficial .<br>**Response:** The SDT uses the term “aggregated” to mean that the requirement refers to the sum of the uses, not individual schedules.<br><br>R9 - The 13th bullet should read: "Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), and |

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| | TTC for all ATC Paths or (TFC) for Flowgates."<br>**Response:** The SDT has deleted "TTC" from the requirement, as it appears to be an editing error.<br><br>M6 - Include reference for TFC, should read: "Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC?"<br>**Response:** The SDT has modified the measure as suggested. |
| **Response:** Please see in-line responses. | |
| Entergy Services Inc | The effective date info provided in the standards posted indicate that all 5 standards should become effective together. It seems that MOD-004 should also be a part of the set becoming effective. CBM is referenced in the posted standards.<br>**Response:** The SDT believes that the existing CBM standards will address the need for a CBM standard during the interim period between the approval of MOD-001,-028, -029, and -030 and the approval of the new MOD-004 is standard. Note that the effective date for concurrent implementation does not include MOD-008.<br><br>R3.2.2.2 The term "accounting" implies bookkeeping and dollars - obviously not something that should be included in a reliability standard. We suggest adding some clarification to this requirement to ensure the intent is clear to all audiences: "A rationale stating how counterflows are accounted for."<br>**Response:** The SDT has modified this language to be more clear.<br><br>R3.3 Change "of" to "or" in added phrase.<br>**Response:** The SDT has made a modification to address this issue.<br><br>M7 - We do not feel that it is prudent to use switching operating guides and load shedding, etc to sell transmission service. To even suggest these in M7 seems misguided and in conflict with the current draft of the TPL standards.<br>**Response:** The SDT believes that switching operating guides are appropriate, and has retained this item. However, load shedding has been removed. .<br><br>R8.2 and 8.3 need a grace period similar to R8.1 to account for unforeseen system emergencies where the selling of ATC is suspended or technology issues.<br>**Response:** Based on the timing requirements associated with R8.2 and 8.3, the SDT has already established inherent 24-hour "grace periods" for daily, and 7-day "grace periods" for weekly. |
| **Response:** Please see in-line responses. | |
| Ontario IESO | We do not see the role of TOP in this standard. The TOP's primary responsibility is to operate its transmission operating area in a reliable manner, and determine SOLs and where necessary, transmission transfer capabilities and flowgate capabilities (where applicable). Given the established SOLs, TTCs, TFCs that are determined by the TOP for operational planning, and |

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| | the TTCs and TFCs determined by other entities such as the RCs, TPs and PCs for wider area and for different time frames, the TSP needs only to calculate ATCs (or AFCs) respecting these established constraints. In doing so, it should be able to select an ATC calculation method to suit its business model and needs, with due consideration to the basis of the TTCs and TFCs that affect its service area. With this in mind, we suggest in our response to Q2, above, that the TSP be the one who selects the ATC method and R1 should be revised accordingly. Note also that it should not be assumed that the TOP area and the TSP area are the same and hence the basis of the TTCs and TFCs that affect the TSP's area may differ from one part to another. |
| **Response:** Please see summary response to Question 2. | |
| Hydro One Networks | In requirement 8, if the 80 days grace period is to account for software outages then say so explicitly in the requirement else entities may interpret the requirement as applicable to outages other then software. |
| **Response:** The SDT discussed whether it was appropriate to limit the requirement to outages only, and felt that to do so would require subjective analysis on the part of a compliance auditor to determine if the outage was legitimate. Rather than do this, the SDT felt it would be more appropriate to set a specific amount of time, independent of cause. Note that the standard as posted mandated 80 hours, not 80 days. | |
| American Transmission Company | The first time that each abbreviation or acronym is introduced, the full terminology should be stated followed by the abbreviation or acronym in brackets (i.e. ATC, AFC, TTC, and TFC).<br>**Response:** The SDT has modified the standards to incorporate this suggested practice.<br><br>The SDT should provide greater explanation as to what would be the proposed effective data of this standard. FERC has justification over all US users, owners and operators of the BPS and following their approval the standard would become "enforceable". Is the SDT proposing that even in the US these standards will not become "enforceable" until all regulatory authorities including Canada and Mexico have approved this set of standards? If this is the case how would NERC insure such a system of enforcement?<br>**Response:** The SDT notes that the language indicates that it is dependent on all applicable regulatory authorities. The intent is that the standards all become effective on the same date across North America; that date will be established one year following all the needed regulatory approvals. |
| **Response:** Please see in-line responses. | |
| Texas-New Mexico Power Company | This standard should not apply to ERCOT for the reason expressed in question 1. |
| **Response:** MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part. | |

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| Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |
| Brazos Electric Power Cooperative, Inc. | As commented in Question #1, Brazos Electric does not believe that the application of ATC to a single control area region would serve any reliability need or commercial market purpose. Therefore an exclusion should be provided in the requirements based on whether a TO/TOP operates solely in a single control area region. |
| **Response:** MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any POR/POD combination for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement. However, if none of ERCOT's neighbors request data from ERCOT, then compliance with R9 would be achieved with no action on ERCOT's part.<br><br>Note that ERCOT may wish to pursue a Variance to this standard. The SDT notes that ERCOT has language in its delegation agreement that states where an ERCOT-specific standard is required, 1) "it shall provide for as much uniformity as possible with (NERC) reliability standards, 2) "it shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. The SDT also notes that, "An ERCOT-Specific Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable." *Texas Regional Entity Standards Development Process, Exhibit C to the Delegation Agreement between NERC and ERCOT.* The SDT believes that a regional variance "Based on a justifiable difference between regions or between sub-regions within the Regional geographic area" could be pursued by ERCOT. *(Loc. Cit.)* | |

| | Individual or group. | Name | Organization | Group Name | Lead Contact | Question 1 | Question 1 Comments | Question 2 | Question 3 | Question 4 | Question 4 Comments | Question 5 | Question 5 Comments | Question 6 Comments |
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| | Individual | | | American Public Power Association | Allen Mosher | No - one or more definitions needs revision - see comments | “Counterflows” should be a defined term. It is used in MOD-1, MOD-28, MOD-29 and MOD-30 and is an integral element in the calculation of ATC and AFC. The definition used in MOD-28-1 R10, for example, reads: “counterflowsF are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.” This definition does not in any way describe what a counterflow is. “Postbacks” should incorporate a working definition developed by NAESB, to be revised once due process is completed on this business practice. Alternatively, consider use of the following text to at minimum describe the nature of postbacks: “PostbacksF are changes to firm [non-firm] ATC [AFC] due to a change in the amount of Firm [non-firm] Transmission Service reserved or scheduled for a period, as defined in Business Practices. Postbacks are generally a positive | Transmission Service Provider | R3.3 - seems awkward for tranfer capability to not be a defined term when TTC and ATC are defined; at minimum, edit to read transfer or Flowgate capability. R3.6 - clarify that "outages" are transmission outages, generator outages or both. R8.1 - why hardwire 80 hours per calendar year during which calculations are not required to be performed? Should this be a compliance Measure? | Yes | | Yes | | Excellent work - my thanks to the SDT members. |

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| | | | | | | | quantity." Also, capitalize existing transmission commitments in the definition of ATC. | | | | | | | |
| | Individual | Paul Rocha | CenterPoint Energy | | | | | | | | | | | The group of standards is for ATC and TRM methodologies that are not used in ERCOT. that ERCOT might have to adopt the ATC and TRM methodologies prescribed in these s not add value to the ERCOT region and could increase congestion in the region. Accordi previously submitted comments to these standards asking for an exemption for the ER standards unacceptable unless the following provision is added to each standard: This s or any other region that operates as a single control area. |
| | Group | | | SERC Available Transfer Capability Working Group (ATCWG) | Dough Bailey | Yes - definitions are acceptable as revised | | No Preference | | Yes | | | | |
| | Individual | John Harmon | The Midwest ISO | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | R3.3 – last line should read: ... calculating ATC or AFC. R3.4 – last line should read: ... calculating ATC or AFC. R3.5 – Each bullet should read: ... allocate ATC or AFC... R6 and R7 – The term 'assumptions' is not specific enough for entities to prepare for compliance. The Midwest ISO requests the standard to list specific assumptions within the scope and what defines 'more limiting' for each of them. For example, is load assumption within the scope? If yes, what load assumption is more limiting? If it is not possible, the Midwest ISO believes that this topic from Order 890 should be left out from any standard and left to FERC to address issues on a case by case basis. R9 – Please expand/clarify the intentions of the 4th bullet. What specific aggregated firm capacity is being referenced? Capacity in ETC for each flowgate as specified by reservations? An example would be very beneficial. R9 – The 13th bullet should read: .. (TRM), and TTC or TFC for all..... M6 – Include reference for TFC, should read: ... used for TTC, or TFC, and Operations Planning.... | Yes | | No | The VSLs for R8 of MOD-001 are inconsistent to the VSLs stated for R10 of MOD-030 although each is related to comparable requirements regarding the frequency of recalculations. If the suggestion of deletion of R10 in MOD-030 is accepted the inconsistency will be addressed. Otherwise, the team should align these VSLs consistently. | |
| | Individual | John Dalessi | Transmission Agency of Northern California | | | Yes - definitions are acceptable as revised | | No Preference | | Yes | | Yes | | R.9 lists many data elements that another entity can request and a TSP is obligated to this data themselves, and R.9 should be clarified to state that the TSP is not obigated t Perhaps this is implied in R9.1, but if so it should be stated more clearly. Also the first s assume the requested data is for use in the requestor's ATC or AFC calculations, but it used in the ATC/AFC calcualation of the TSP receiving the request. |
| | | | | | | | | | MOD-01, R9. Could the NERC Team please clarify "which" Load | | | | | |

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| Group | | | WECC Market Interface Committee / Sub Commtt / ATC Task Force | W. Shannon Black | Yes - definitions are acceptable as revised | | Transmission Service Provider | Forecast it is requesting? Hourly? Daily? For what affected area? MOD-01, R9. Could the NERC Team please clarify that Block/Dispatch Order and Participation Factors do not call for the submission of specific schedules; rather, these defintions only call for dispatch rules from which approximations can be made. | Yes | | Yes | | |
| Group | | | Southwest Power Pool | Kevin Bates | Yes - definitions are acceptable as revised | | | | Yes | | | | R3.6.3. How outages (including those outages from other Transmission Service Provide processed. Define "unrecognized." Does this also refer to outages that are not used bec outside the TSP's model and therefore do not impact calculations? ________________ R9. Within thirty calendar days of receiving a request by any Transmission Service Prov Reliability Coordinator, or Transmission Operator for data from the list below for use in Transmission Service Provider receiving said request shall begin to make the requested subject to the conditions specified in R9.1 and R9.2: The concern of R9 is numerous re unnecessary burden for TSPs fulfilling said requests. SPP feels a justification should be comunication between requestor and TSP so desired result is obtained. |
| Individual | Maria Neufeld | Manitoba Hydro | | | Yes - definitions are acceptable as revised | | No Preference | | Yes | | Yes | | |
| Individual | Jack Cashin/Barry Green | EPSA | | | Yes - definitions are acceptable as revised | | No Preference | R6/7. I believe the wording of this requirement in the previous draft was superior. In the revised language, deletion of the word "consistent" allows for discontinuities in the ATC calculations. For example, if the assumptions used in "planning of operations" in the period beyond one month are different than for those in the current month, this could create discontinuities where the calculations adopt different assumptions. In addition, the current language has broken the explicit link between planning studies and operations studies. | | no comment | | NO COMMENT | We offer two additional comments. First, with respect to the purpose of this standard, previous draft was more appropriate. The previous draft stated that consistency in the documentation were part of the purpose of this standard. We believe those are importa included. Secondly, requirement 3.2 dealing with counterflows is insufficient in the curr consistency in the use of counterflows on all interfaces would not be appropriate. Indee single system, it is likely appropriate that the counterflows on some interfaces be treat historical usage of the interface. However, to create a standard that requires only an id and a statement of the rationale, with no guidance on appropriate methodologies or ac sufficiently enforceable and amounts to a fill-in-the-blank standard. |
| Group | | | Public Service Commission of South Carolina | Phil Riley | Yes - definitions are acceptable as revised | | No Preference | | Yes | | Yes | | |
| | | | | | | | | Requirement 2 •While the IRC understands that the SDT believes that the requirements need to address the amount of ATC or AFC data calculated and the frequency of calculation associated with them, these requirements should be business practices and should be considered NAESB scope and | | | | | |

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| | Group | | | ISO RTO Council/Standards Review Committee (SRC) | Charles Young | Yes - definitions are acceptable as revised | | | eliminated from the MOD Standards. The MODs can still address FERC orders and be reliability based without the MOD-001 R2 (amount of ATC or AFC) and R8 (frequency ATC recalculation) and MOD-030 R10 (frequency AFC recalculation) requirements. The violation severity levels for these draft standards now have a graded implementation. The possibility of multiple violations resulting from a single event still remains. The IRC requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. This language should be added to the standard as a new item 6 to section A of MOD-001. Requirement 3 •R3.2.1 - The IRC understands the SDT's reasons for using “Confirmed” reservations in accordance with the FERC regulations. However, reservations that are in “Accepted”, as well as, “Confirmed” status should be included. Once service is “Accepted” by a TSP it cannot be retracted. Using reservations that are in “Accepted” and “Confirmed” status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TSP from decrementing for accepted and confirmed TSRs. We understand that some TSPs maintain two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TSPs who maintain two sets of ATC values to post the “internal” ATC values to provide greater transparency and | Yes | The MOD standards assess the correct amount of reliability risk in areas that do not affect reliability. The IRC supports the position that no requirement from this set of ATC standards should have an assigned Risk Factor exceeding “Lower”. A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of | No | ERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but the IRC has a concern regarding the possibility of multiple violations resulting from a single event. The IRC requests that double counting of violations for a single event be eliminated. The IRC recommends that the SDT add a new item 6 to section A of MOD-001 that states "A single event shall not result in multiple violations". A review of MOD-001 R2 and R8 should be performed for determination of multiple violations resulting from one event. | The IRC applauds the efforts of the NERC Standards Drafting Team (SDT) in providing a comment that include many of the Industry's comments from the Ballot. However, ther require modification. The MOD standards extend into areas that should be covered and Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency be NAESB Business Practices, and not included in the NERC Standards as reliability bas details for MOD-001 R2 and R7). Non-firm should be removed from this reliability stand |

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| | | | | | | | | | give customers a more accurate picture of capability available to new requests. •R3.6 - For R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD 1 and applied consistently across MODS 28, 29 and 30. Requirement 8 •If R8 is not moved to NAESB Business Practices then revise R8.1 and the VSL to align the requirement and NAESB practice which allows OASIS to be down 2% of the time over a year. Modify the 80 hour per year allowable outage requirement to 175 hours per year (8760 hrs/year x 0.02= 175 hours). This VSL does not become a possible sanction until the accumulated amount of hours missed exceeds 175 hours. The 175 hours is for planned, system IT outages. Unplanned, system IT outages should not be included in this total. | | the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. | | | |
| | | | | | | | | | Requirement 1: I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall select one ATC methodology for calculating ATC (Area Interchange methodology, Rated System Path methodology)or AFC (Flow gate methodology) for each ATC Path per time period identified in R2 for those facilities within its Transmission Service Provider area." Comment: The TOP is to operate its transmission operating area in a reliable manner and ensure SOLs are determined. ATC is a transmission service market concept, not a reliability function. In areas where there is a transmission service market in operation, there is some reliability | | | | | |

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| | Individual | H. Steven Myers | ERCOT ISO | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | value to having a representative ATC in play to ensure proper planning is conducted, but reliability is ensured by adherance to the SOLs of the system, not by adherance to ATC. Requirement 3: I suggest modifying the requirement to state: "Each Transmission Service Provider with ATC Path(s) shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information:" Requirement 4: I suggest modifying the requirement to state: "The Transmission Service Provider with ATC Path(s) shall notify the following entities (via electronic mail) before implementing a new or revised ATCID." Requirement 5: I suggest modifying the requirement to state: "The Transmission Service Provider with ATC Path(s) shall make available the current ATCID to all of the entities specified in R4." Requirement 6: I suggest modifying the requirement to state: "When calculating TTC or TFC, the Transmission Service Provider with ATC Path(s) shall use assumptions no more limiting than the estimated SOLs used in planning of operations for the corresponding time period studied." Requirement 7: I suggest modifying the requirement to read: "When calculating ATC or AFC, the Transmission Service Provider with ATC Path(s) shall use assumptions no more limiting than the estimated SOLs used in planning of operations for the corresponding time period studied." Requirement 8: I suggest modifying the requirement to state: "Within 30 calendar days of receiving a request by any Transmission | | | | | I suggest modifying the Applicability section to state: 4.1 Transmission Service Provide Transmission Oerator with ATC Path(s) Comment: It is unclear how failing to meet the grid reliability. This should be a commercial standard or a business practice rather than Severity Levels: Violation of timeing requirements should not constitute a severe violat failure to attempt to perform the task at all. A high violation could be a long failure to p NO attempted corrective action. All other failures in timing should be lower violation se |

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| | | | | | | | | | Service Provider, Planning Coordinator, or Reliability Coordinator for data from the list below for use in ATC or AFC calculations, each Transmission Service Provider with ATC Path(s) receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2." Requirement 9.1: I suggest modifying the sub-requirement to state: "The Transmission Service Provider with ATC Path(s) shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months in the future (subject to confidentiality and security requirements)." Requirement 9.2: I suggest modifying the sub-requirement to state: "This data shall be made available by the Transmission Service Provider with ATC Path(s) on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requestor and the provider)." | | | | | |
| | Individual | Aaron Staley | Orlando Utilities Commission | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | | Yes | | Yes | | Overall Question: As written currently, the standard appears to set requirements for ca but does not require an entity to perform the calculation. For example, R1 and R6 appl TOP doesn't calculate ATC/AFC/TTC/TFC then nothing in the requirements seems to obl seems to be true of the requirements that apply to a TSP. Is this a correct reading of tl If the drafting team changes the responsible entity in Requirement 1, will they also cha What if there is not "planning of operations" activity for the corresponding time period? have an ATC study done, it may not have a corresponding "planning of operations" acti you provide some examples of what you mean by "assumptions". Requirement 6 & 7: \ these requirements, specifically what is the reliability purpose of setting a maximum th assumption can be? |
| | Group | | | WECC Market Interface Committee ATC Task Force | W. Shannon Black | Yes - definitions are acceptable as revised | | Transmission Service Provider | Mod-001, R9. Could the NERC Team please clarify "which" Load Forecast it is requesting? Hourly? Daily? For what affected area? MOD-001, R9. Could the NERC Team please clarify that Block/Dispatch Order and Participation Factors do not call for the submission of specific schedules; rather, these definitions only call for dispatch rules from which approximations can | Yes | | Yes | | |

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| | | | | | | | | | be made. | | | | | |
| | Individual | Patrick Brown | PJM | | | Yes - definitions are acceptable as revised | | Transmission Operator | Requirement 2 • While PJM understands that the SDT believes that the requirements need to address the amount of ATC or AFC data calculated and the frequency of calculation associated with them, these requirements should be business practices and should be considered NAESB scope and eliminated from the MOD Standards. The MODs can still address FERC orders and be reliability based without the MOD-001 R2 (amount of ATC or AFC) and R8 (frequency ATC recalculation) and MOD-030 R10 (frequency AFC recalculation) requirements. The violation severity levels for these draft standards now have a graded implementation. The possibility of multiple violations resulting from a single event still remains. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. This language should be added to the standard as a new item 6 to section A of MOD-001. Requirement 3 • R3.2.1 - PJM understands the SDT's reasons for using “Confirmed” reservations in accordance with the FERC regulations. However, reservations that are in “Accepted”, as well as, “Confirmed” status should be included. Once service is “Accepted” by a TSP it cannot be retracted. Using reservations that are in “Accepted” and “Confirmed” status should also be included in MOD-030 R6.3, R6.4, R7.1, and R7.2. This does not prevent the TP from decrementing for accepted and confirmed TSRs. We understand that some TPs maintain | Yes | PJM supports NERC's position to revise all Violation Risk Factors to have an assigned risk factor of “Lower.” A Lower Risk Factor requirement is administrative in nature and is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk | No | NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now, for the most part, have a graded implementation, but PJM has a concern regarding the possibility of multiple violations resulting from a single event. PJM requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations –this language to be | Depth of the ATC MOD standards extends beyond the scope of the reliability standards areas that should be covered and addressed by NAESB Business Practices (as defined i frequency of postings and frequency of AFC/ATC calculations should be NAESB Busines NERC Standards as reliability based requirements (see specific details for MOD-001 R2 Specific Comments sections below). Non-firm should be removed from this reliability st |

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| | | | | | | | | | two sets of ATCs. One set is maintained internally and accounts for accepted and confirmed TSRs. The other set of ATC values is maintained externally and only accounts for confirmed TSRs. It is important for TPs who maintain two sets of ATC values to post the “internal” ATC values to provide greater transparency and give customers a more accurate picture of capability available to new requests. • R3.6 - For R3.6 in MOD 001 requires outages to be included in the daily and monthly calculations. R5.2 in MOD 30 requires outages to be included in the hourly calculations. A single requirement should be placed in MOD 1 and applied consistently across MODS 28, 29 and 30. Requirement 8 • If R8 is not moved to NAESB Business Practices then revise R8.1 and the VSL to align the requirement and NAESB practice which allows OASIS to be down 2% of the time over a year. Modify the 80 hour per year allowable outage requirement to 175 hours per year (8760 hrs/year x 0.02= 175 hours). This VSL does not become a possible sanction until the accumulated amount of hours missed exceeds 175 hours. The 175 hours is for planned, system IT outages. Unplanned, system IT outages should not be included in this total. | | power system, or the ability to effectively monitor and control the bulk power system. | | added to the standard. Add a new item 6 to section A of MOD-001. For example a review of MOD-001 R2 and R8 and MOD-30 R10 should be performed for determination of multiple violations resulting from one event. | |
| | | | | | | | | | | | | | | These comments are filed on behalf of City of Austin d/b/a Austin Energy to address pr Austin Energy is a municipally owned electric utility and a transmission service provider Council of Texas (ERCOT). ERCOT now operates as a Single Balancing Authority with no being sold. Current ERCOT market rules allow open transmission access to all loads and operate as a Single Balancing Authority under Nodal market design. Accordingly, as exp NERC 5 MOD Standards should not be applied to ERCOT and transmission service provi current or proposed Nodal market design. Austin Energy requests that the NERC Stand to these Standards to clarify that MOD-001-1, MOD-008-1, MOD-028-1, MOD-029-1, a applicable to regions with a Single Balancing Authority that do not use ATC methodolog their market operations. Applicable definitions: According to NERC Reliability Standards Transfer Capability (ATC) is defined as: “A measure of the transfer capability remaining network for further commercial activity over and above already committed uses. It is d (TTC) less existing transmission commitments (including retail customer service), less a less a Transmission Reliability Margin (TRM), plus Postbacks, plus counterflows”. TTC is power that can be transferred over the interconnected transmission network in a reliab specific set of defined pre- and post-contingency system conditions. CBM is defined as transfer capability reserved by load serving entities to ensure access to generation from generation reliability requirements. TRM also is a component of ATC defined as: that ar capability necessary to ensure that the interconnected transmission network is secure u uncertainties in system conditions. Comments: ERCOT is an interconnection and a regi |

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| | Group | | | Electric Service Delivery | Reza Ebrahimian | | | | | | | | | with any other interconnections. In July 2001, based on a deregulated Retail and restru<br>ERCOT interconnection began acting as a Single Balancing Authority. The ERCOT marke<br>no explicit transmission services being sold, hence, Available Transfer Capability (ATC)<br>commercial activity within the ERCOT market. The current ERCOT market rules allow o<br>eligible loads and resources without considering any specific Transmission Service Prov<br>ratings are based upon individual branch element designs and in cases of dynamic ratir<br>considered. ERCOT has several DC ties and an asynchronous tie using a Variable Frequ<br>the associated interchange capabilities are planned and coordinated by the TSPs involv<br>Market uses a flow based congestion management methodology to predict potential co<br>Adjustment Periods. During the operating period, generation shift factors are used to d<br>remain within the constrained limits. The local congestions are managed using full AC l<br>redispatch. MOD-001-1 is entirely about methodology and calculation of ATC, therefore<br>ERCOT. MOD-008-1 covers Transmission Reliability Margin (TRM) methodology calculat<br>defined as Total Transfer Capability (TTC) less the TRM and Capacity Benefit Margin (C<br>applicable to ERCOT. MOD-028-1 covers Area Interchange calculation Methodology. Sir<br>Area Interchange calculation is not applicable. MOD-029-1 covers Rated System Path M<br>calculate TTC and ATC calculations. Therefore MOD-029-1 is not applicable to ERCOT. M<br>methodology calculation of ATC, and therefore, is not applicable to ERCOT. ERCOT is cu<br>Market, with a scheduled start date of December 1, 2008. The Nodal Market uses a Sec<br>Dispatch (SCED) approach to dispatch individual generating units and manage congesti<br>will still operate as a Single Balancing Authority. This again will not use ATC methodolo<br>are not applicable to ERCOT in its ensuing Nodal Market. Therefore, Austin Energy requ<br>Drafting team add language to these Standards to clarify that MOD-001-1, MOD-008-1<br>MOD-030-1 Standards are not applicable to regions with a Single Balancing Authority t<br>and any of its components in their market operations. |
| | Individual | Frank Cumpton | California ISO | | | Yes - definitions are acceptable as revised | Please see comments given ion last question. | | | | | | | Purpose – The MOD 1 Purpose as presently written does not clearly relate the intent of<br>Purpose statement should be more explicit, i.e. “To require that ATC calculations are pe<br>and HA) and forecasted system operating conditions on ATC Paths”, using one or more<br>embodied in MOD 28 – 30. Purpose should clearly state “for ATC Paths”, and then clear<br>MOD 1 CFR definition of “ATC Path” is very open to interpretation, given that “ATC Path<br>Path” via a footnote reference to 18 CFR 37.6(b)(1) OR “any OTHER combination of PO<br>calculated”. Posted Path implies a requirement to post the ATC to an OASIS site, and to<br>referenced path. The MOD 1 “ATC” definition does refer to the intention that ATC is cal<br>activity”. Presumption is that the ATC is posted for sale. ATC Path Definition – Clarify th<br>applicable ONLY to interties and internal paths between systems where Transmission is<br>activity). Clarify if ANY posting requirement is embodied in these standards. Explanatio<br>interpretation is that under MOD 1 and 29, the ISO will be required to calculate and pos<br>The ISO will use the MOD 29 Rated System Path Methodology to calculate ATCs DA, HA<br>timeframes, consistent with practice in the WECC for interchange ratings. However, the<br>based Integrated forward Market under its new MRTU Market design to be implemented<br>will use an Integrated Forward Market in combination with an Full Network Model and L<br>imports and exports, procure AS and Balancing energy for RT, to optimize use of the gr<br>flowgates in the 3000 node FNM. However, the ISO will only be posting ATCs for transr<br>consistent with our Market design and interpretation of the definition of ATC Path, prov<br>standards. Note; The CAISO operates the combined transmission assets of 11 TOs loca<br>one Transmission system for Market purposes. Is this interpretation consistent with the<br>believe that MOD 30 contains any requirement to convert the IFM's use of flow gates to<br>not related to ATC Paths, as defined by MOD 1? This would appear to be very impractic<br>benefit, as the power flow solution used to dispatch energy in the IFM is only known aft<br>flow solution is reached for each of the thousands of interconnected transmission eleme<br>nodal bus network. R2 & R8 – Should the actual ATC Calculation timing requirements to<br>Standard??? Any requirement to calculate and post ATC with any accuracy, should be li<br>perhaps weekly values. The requirement to calculate Monthly and yearly ATC values be<br>requirements and beyond any reasonable expectation of knowledge of operating condit<br>CAISO Market construct. Posting of ATC for timeframes beyond seven days would seem<br>knowing what the operationally constraints would be to any degree of accuracy (I.e. hy<br>planned generation and transmission outages, planned maintenance work). R9 - Does t<br>CAISO release our power flow model to our TO's, absent a NDA??? See 9th bullet. |
| | Group | | | NERC RTOSDT | Jim Case, Chair | | | | | | | | | The Real Time Operation Standards Drafting Team is concerned that the proposed MOD<br>reference to the Planning and Operating Limits mandated by the current FAC, IRO and<br>already include transmission flow limits both in the longer term planning time frame as<br>time frame. The proposed MOD standards seem to be establishing procedures to calcul<br>without a direct link to the required reliability boundaries.<br>=====================================================<br>that the TTC “use assumptions” no more limiting than those used in planning. The RTO<br>required to be “no less limiting” than the SOLs / IROLs computed for the system? Curre<br>asset limits, they are also system limits. The current standards require that limits be ca<br>and wide-area impacts. The RTO SDT believes that by at least linking (if not entirely eli<br>the current SOLs / IROLs requirements, the Industry would be more correctly linking h<br>to any NAESB business practice. Indeed it would seem that current tariffs are based on<br>planning and operating environments. By using the current SOL / IROL limits the proce<br>MOD-001 R9 et al would be unnecessary (i.e. they would revert back to the FAC and IR<br>the ATC SDT: • How do these MOD standards relate to the SOLs / IROLs • Why should<br>from the SOLs / IROLs • Shouldn't the long-term SOL / IROL limits computed in Plannin<br>least the basis for the TTC) • Shouldn't the short-term SOL / IROL be the basis for the<br>computes margins. By coordinating the MOD standards with the SOL / IROL standards,<br>requirement may be to define the options on how the TSP could couple the various SOL<br>its RCs and TOPs. MOD-028 By using SOLs / IROLs there would be no need to get into<br>Indeed standards that include “alternatives” are not defining a single “standard approa<br>and operating limits the methodologies become irrelevant. The “limit” becomes explicit<br>variations about those limits would then be obvious and transparent. What is most imp<br>based limits and not how the commercial value is computed. If this idea of using SOLs<br>the basis for those commercial limits, then the TSP becomes a coordinator of which val<br>periods. The TSP would not be the computer of those limits. Thus MOD-028 could beco<br>– rather then a standard for computations. |

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| | Group | | | NPCC Regional Standards Committee | Guy V. Zito | Yes - definitions are acceptable as revised | | Transmission Service Provider | NPCC Participating Members have the following comments on specific requirements 1. R3.6.3: This subrequirement is too vague and its addition is not necessary. Subrequirements R3.6.1 and R3.6.2 suffice to hold the TSP responsible for considering the impact of outages in ATC calculation. How the outages are processed has no bearing on the ultimate scenarios (topologies) that the TSP must consider. 2. Also we do not agree with the changes made to R6 and R7. By “no more limiting than” the assumptions used in planning of operations for the same time period, it would imply that the TOP and TSP may use less restrictive (or more liberal) assumptions. The results could be that the TTCs and ATCs are higher than the planned operational parameters, giving rise to potential unreliability. We do not see a problem with the previous wording of “consistent with”, and this should be reinstated | Yes | | No | NPCC Participating Members have the following comments on the VSL: 1. R3: There is a potential overlap between High and Severe. For an ATCID does not include “two or more” of the information items in R3, it could mean does not include all of the information items. This is the same condition as a Severe. We suggest to reword the High VSL to “does not include up to 2 of the information items in R3”; and the Severe VSL to “or its ATCID does not include 3 or more of the information described in R3”, or numbers along that line. 2. We do not agree with the VSLs for R6 and R7 for reasons noted under Q3, above. | NPCC Participating Members do not see the role of TOP in this standard. The TOP’s prin transmission operating area in a reliable manner, and determine SOLs and where neces capabilities and flowgate capabilities (where applicable). Given the established SOLs, T the TOP for operational planning, and the TTCs and TFCs determined by other entities s wider area and for different time frames, the TSP needs only to calculate ATCs (or AFCs constraints. In doing so, it should be able to select an ATC calculation method to suit it due consideration to the basis of the TTCs and TFCs that affect its service area. With th response to Q2, above, that the TSP be the one who selects the ATC method and R1 sh also that it should not be assumed that the TOP area and the TSP area are the same ar TFCs that affect the TSP’s area may differ from one part to another. Also we believe the the method to be used in calculating available transmission transfer capability since it i processing transmission services, not the TOP. In determining ATCs, the TSP needs to determined by the TOPs, RCs, TPs and PCs. Keeping the determination of TTCs (TFCs) ATC, including the latter’s methodology, would be the appropriate approach in moving standards. |
| | | | | | | | | | R1- The selection of a calculation methodology should reside with the party responsible for calculating ATC. As stated in question 2, FE believes that R1, the selection of an ATC methodology, should be applicable to the Transmission Service Provider (TSP) and not the Transmission Operator since within many RTO areas it is the TSP who maintains the ATC methodology documentation and performs the ATC calculations. This is the case in a large portion of the continent and a standard should not be written in a way that would knowingly require an assignment delegation for a large number of potential responsible entities. Assigning the requirement | | | | | |

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| | Group | | | FirstEnergy | Doug Hohlbaugh | Yes - definitions are acceptable as revised | | Transmission Service Provider | responsibility to the TSP would also work for non-market areas of the continent where a TO/TOP also serves as its own its own TSP. The TOP should provide a support role in providing data and information that is needed by the TSP to fulfill its responsibilities in calculating ATC. The TSP is overseeing transmission service requests and making determination of the viability of such requests. The TOP has ultimate reliability responsibility in the real-time environment and will manage its system to its system operating limits regardless of the ATC methodology used by its TSP to approve transactions that make use of the transmission operator's system. R3.3 – There appears to be a typo. Replace "of" in the words "transfer of Flowgate capability" with "or" R3.3, R3.4, R3.5 – Suggest the SDT consider replacing the words "transfer or Flowgate capability" with "ATC or AFC" to improve readability. R3.6 – Replace "ATC" with "ATC or AFC". R3.6 (sub-requirements) - The sub-requirements of R3.6 require that outages be included in the daily and monthly calculations, but excludes hourly calculation periods. In MOD-030 (AFC Methodology) requirement R5.2 requires expected transmission and generation outages are included for all applicable time period calculated. It is suggested that a single requirement reside in MOD-001 to cover the hourly, daily and monthly aspects for this intent that would assure consistent application across the MOD-028, MOD-029 and MOD-030 standards. R8 – It is not clear why the frequency for recalculation is only | Yes | FE supports the SDT's adjustment of VRFs such that no VRF within the ATC standards exceeds a "Lower" rating. We concur with the team's reasoning and rationale provided in response to ballot comments in making this change. | No | The VSLs for R8 of MOD-001 are inconsistent to the VSLs stated for R10 of MOD-030 although each are related to comparable requirements regarding the frequency of recalculations. If the above suggestion revising MOD-001 R8 and deletion of R10 in MOD-030 is accepted the inconsistency will be addressed. Otherwise, the team should align these VSLs consistently. | FirstEnergy appreciates the Standard Drafting Team's decision to move to a formal com initial ballot feedback. We commend the team for moving quickly to respond to the ball industry a revised set of standards to review and comment. Regarding the revision to t FirstEnergy agrees that there is a need to ensure that the standard is implemented con continent we are concerned with the Effective Date being subject to approval of ALL reg appropriate Implementation Plan should reflect a period of time beyond the NERC Boar would reflect when the requirements are considered mandatory and enforceable. The ti for regulatory authority reviews, with the intent of sanctions also being enforced in con implementation period. However, a delay from a given regulatory agency should not im considered mandatory and enforceable for the bulk electric system. |

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| | | | | | | | | | focused on ATC, and does not read "ATC or AFC", similar to the wording used for calculating in R2. In MOD-030 R10 addresses recalculation for the AFC but it seems that with the suggested change in R8 of MOD-001, that R10 of MOD-030 could be eliminated. Additionally they are inconsistent in that R10 does not provide for the 80 hour annual allowance that is stated in R8. | | | | | |
| | Individual | Thad Ness | AEP | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | | | | | | The Applicability of this Standard should be solely upon the TSP, the Transmission Ope Standard. From the previous set of responses, it is the apparent belief of the SDT that for reliability (response to AECI for example). We disagree. Considering that ATC is a n forecasted system conditions (load, outages, generation dispatch, others' transactions, margins (TRM and CBM of own entity and other systems), using the calculated ATC to a transmission reliability would be – at best – unwise. Transmission Reliability can be ass individual Facility loadings and/or other parameters, for example. The calculation of AT exactly for the purpose stated in the definition of ATC: "A measure of … capability….for note the definition does not infer ATC is a measure of reliability. Granted, ATC is calcula values and concepts (such as ratings, contingency analysis aspects, SOLs etc), BUT the assessment of transmission reliability – and therefore not a function for the Transmissi Transmission Service Provider. |
| | Group | | | PPL Supply Group | Annette Bannon | | | | R4. PPL suggests that Purchasing/Selling Entities should be included in the listing of entities under Requirement R4 who have access to the ATCID. R8. PPL suggests that the following changes be made to the calculation time periods: R8.1 should require hourly ATC to be calculated "as close to continuously as possible". Once per hour is too slow. R8.2 should require daily ATC to be calculated at 15 minute or less intervals. Once per day is too slow. R8.3 should require that Monthly ATC be calculated hourly or at most daily. Once per week is too slow. | | | | | PPL suggests that the standard should require that the TSP make available the new AT |
| | Individual | Greg Rowland | Duke Energy Corporation | | | No - one or more definitions needs revision - see comments | ATC path : Insert the phrase "or Available Flowgate Capability" after the phrase "Available Transfer | Transmission Operator | R8.1 – The following sentence, "Transmission Service Providers are allowed up to 80 hours per calendar year during which calculations are not required to be performed." appears somewhat capricious and should be clarified to show the drafting team's intentions. As presented, it would permit a TP to decide not to calculate hourly ATC for a 3 1/3 day period. Also, R8 does not require | Yes | | Yes | | |

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| | | | | | | | Capability". | | recalculation if none of the calculated values identified in the ATC equation have changed. Does R8.1 limit the exemption provided in R8 to 80 hours per year? M7 - insert the phrase "list of contingencies," before the phrase "loop flow". | | | | | |
| | Individual | Greg Ward / Darryl Curtis | Oncor Electric Delivery | | | No - one or more definitions needs revision - see comments | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Oncor is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, Oncor believes that implementation of the prescribed methodologies would add no value to the ERCOT market and could result in more system congestion. Oncor strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). | No Preference | | Yes | | Yes | | This standard should not apply to ERCOT for the reason expressed in question 1. |
| | Group | | | Bonneville Power Administration | Denise Koehn | Yes - definitions are acceptable as revised | | Transmission Operator | BPA does not believe any are incorrect. | Yes | | Yes | | BPA thanks the drafting team for the modifying MOD-001 to not require the conversion your assessment that there is no reliability need for such conversion. Additionally, BPA observations and suggestions: a. The purpose statement of MOD-001 be modified as fo 890-A: Purpose: To ensure the consistent and transparent application and documentati used in the calculation of Available Transfer Capability (ATC) or Available Flowgate Cap listed for all requirements should include the "Long-term Planning" Horizon, as ATC or seasonal window. c. Balancing Authorities may be appropriately identified as Applicable request that the Standards Drafting Team provide an explanation as to why they are n |
| | Individual | Alice Druffel | Xcel Energy | | | Yes - definitions are acceptable as revised | | | 1) R3.6.3 Need to strike "that are unrecognized". The term "unrecognized" is problematic and vague. 2) R3.2.2 Please clarify what you mean by "defined accounting". 3) R3.3 | Yes | | Yes | | We feel that the applicability of this standard as proposed is problematic. We also do n is resolved by choosing either the TOP or TSP. While it is not a perfect solution, we feel applicability to remain at the regional level. We suggest the following wording: "Region its members". |

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| | | | | | | | | | There is a typo. Please change "of" to "or". | | | | | |
| | Individual | Earl Fair | Gainesville Regional Utilities | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | R1: In reading the standard and the definitions, it seems that the std. doesn"t require an entity to calculate TTC/TFC/AFC, but only tells them how it must be done if it is to be done at all. Am I understanding this requirement correctly? R6: If the responsible entity is changed in R1, with it also be changed in this requirement as well? R6&7: If for example a study for month 10 may not have a corresponding "planning of operations" activity, what action is required to fulfill this requriement? R6&7: What is meant by " assumptions"? Can the team provide some GOOD examples? R6&7: I do not see a reliability purpose of these 2 requirements. I do not see how setting a maximum threshold on limiting assumptions can support a reliability interest. | Yes | | Yes | | None at this time. |
| | Individual | Richard Kafka | Pepco Holdings, Inc. | | | | | Transmission Operator | PHI supports the comments of PJM and will not duplicate the submission of comments | | | | | |
| | | | | | | | | | 1. The MRO agrees with the changes made to replace "ATC" with "ATC or AFC" in the standards. However, the MRO believes this change should be made to R3.6 should be revised this way as well to say "A description of how outages are considered in ATC or AFC calculations, including:". 2. The MRO continues to believe that R4 should be revised to match M4 "The Transmission Service Provider shall provide evidence (such as dated electronic mail messages) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)" The MRO does not see the reliability need to specify the | | | | | |

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| | Group | | | MRO NERC Standards Review Subcommittee | Tom Mielnik | No - one or more definitions needs revision - see comments | The MRO supports the changes to the definitions. However, the MRO believes there is a need to define "counterflows". The MRO suggests that the SDT consider the following definition for Counterflows: "Counterflows are net impacts on a path or flowgate as determined by the Transmission Service Provider and specified in the appropriate implementation document." Capitalize "Existing Transmission Commitments" in the Available Transfer capability definition, since it is a defined term. | Transmission Service Provider | media via how the Transmission Service Provider notifies the following entities. However, if the issue is that the SDT believes that there must be a record of the notification, the MRO suggests that the words "in writing" be used allowing the Transmission Service Provider to determine the media of notification. 3. The MRO believes that R8 should also be revised to refer to "ATC or AFC" rather than just "ATC". 4. The MRO believes that R5 should be revised to delete the words "all of". The phrase "all of" seems to be unnecessary and may result in over-the-top auditing. 5. The MRO believes that the changes made to R6 are a significant improvement to the standard and commends the SDT on taking this more reasonable approach to consistency, that is "no more limiting than those used in planning of operations." 6. The MRO believes that R9 should be revised to delete the words "any" from "Within thirty calendar days of receiving a request by any Transmission Service Provider…". R9 should be revised to delete the words "all" from "Unit commitments and order of dispatch, to include all designated network resources…". R9 should be revised to delete the words "Any" from the phrase "Any firm and non-firm adjustments…". R9 should be revised to delete the words "Any" from the phrase "Any other services that that impact …..". R9 should be revised to delete the word "all" from "Values of CBM and TRM and TTC for all ATC [paths or Flowgates." R9 should be revised to delete "any" from the phrase "any Flowgates considered by the Transmission Service | Yes | The MRO commends the SDT in the changes made to VRFs to Lower. The MRO agrees that these changes puts the VRFs more in line with the NERC's definitions of the VRF levels. | Yes | | 1. The MRO commends the SDT in making significant changes to this standard and reis believes the eventual standard that is approved will serve the industry and customers b believes that the first time you use an abbreviation or acronym, you must spell out the abbreviation or acronym in brackets. Subsequent use of the term is then made by its a Transmission Operator shall select one Available Transfer Capability (ATC) methodolog Interchange methodology, Rated System Path methodology) or Available Flowgate Cap methodology) for each ATC Path per time period identified in R2 for those Facilities wit Area." R3.3 – last line should read: …calculating ATC or AFC. R3.4 – last line should re – Each bullet should read: …allocate ATC or AFC… R6 and R7 – Overall, both requireme MRO asks that the standards drafting team specify what assumptions are referenced o Also the MRO objects the requirement to use assumptions that are no more limiting in result in potentionally onorous calcualations to determine assumtions that meet this lin requirements are covered by FERC order #890 anyway. R9 – Please expand/clarify the specific aggregated firm capacity is being referenced? Capacity in ETC for each flowgat example would be very beneficial. R9 – The 13th bullet should read: "Values of Capaci Transmission Reliability Margin (TRM),and TTC for all ATC Paths or (TFC) for Flowgates should read: "Alternatively the Transmission Operator may demonstrate that the same TTC or TFC…" |

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| | | | | | | | | | Provider receiving the request..." R9 should be revised to delete the word "all" from the phrase "Values of TTC and ATC for all ATC Paths for those...". These uses of "any" and "all" seem to be unnecessary and may result in over-the-top auditing. 7. The MRO believes comparable changes should be made to deleting "all" and "any" in the Measures, the Compliance section, and the Violations Severity Levels to match the changes to R9. 8. R3.6.3 Need to strike "that are unrecognized". The term "unrecognized" is problematic and vague. 9. R3.2.2 Alternate language for the statement "a rationale for the defined accounting" A suggestion to use counterflow process instead. 10. R3.3 There is a typo. Please change "of" to "or". | | | | | |
| | | | | | | | | | R3.3 - Replace "--- transfer of Flowgate capability." by "--- transfer or Flowgate capability." R3.6.3 - Entergy is not sure what the parenthetical is implying, specifically the phrase, "that are unrecognized." In addition, Entergy proposes that rather than processing of outages, it should refer to modeling of outages in ATC calculations, therfore, replace "processed" by "modeled". R6 and R7 - The phrase "planning of operations" may be better understood if the term "reliability" was inserted at the beginning. We assume that the SDT is trying to tie the reliability planning studies/activities to the ATC calculations. Similar terms are used in MOD-030. (This also raises the question of why it is in MOD-030 and not MOD-028 and MOD-029.) If all instances can use the same phrase, we think the standards would benefit from the standardization. R8.1 needs to be | | | | | |

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| Group | | | Entergy Services Inc | Narinder K. Saini | Yes - definitions are acceptable as revised | Revised definitions are acceptable | Transmission Operator | worded as requirement rather than giving allowance/exemption from the requirement for 80 hours (approx 1% of 8760 hours) in a calendar year. Entergy recommends the language "Hourly values, once per hour at least 99% of hours every calendar year." R9 - This requirement is for sharing the data by TSP with others who need it for calculation of their ATCs. This requirement is not to replace the requirement of Order 889 37.6(b)(2)(ii) "On request, the Responsible Party must make all data used to calculate ATC and TTC for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (e.g., thermal, voltage, stability)) in electronic form within one week of the posting. The information is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material." If it can be emphasized this fact, it will greatly clarify some confusion that some stakeholders are having regarding data sharing. | Yes | | Yes | | The effective date info provided in the standards posted indicate that all 5 standards sh<br>seems that MOD-004 should also be a part of the set becoming effective. CBM is refere<br>R3.2.2.2 The term "accounting" implies bookkeeping and dollars - obviously not sometl<br>reliability standard. We suggest adding some clarification to this requirement to ensure<br>audiences: "A rationale stating how counterflows are accounted for." R3.3 Change "of"<br>do not feel that it is prudent to use switching operating guides and load shedding, etc t<br>even suggest these in M7 seems misguided and in conflict with the current draft of the<br>a grace period similar to R8.1 to account for unforeseen system emergencies where the<br>technology issues. |
| Individual | Ron Falsetti | Ontario IESO | | | Yes - definitions are | | Transmission Service | We have the following comments on specific requirements: 1. R3.6.3: This subrequirement is too vague and its addition is not necessary. Subrequirements R3.6.1 and R3.6.2 suffice to hold the TSP responsible for considering the impact of outages in ATC calculation. How the outages are processed has no bearing on the ultimate scenarios (topologies) that the TSP must consider. 2. We do not agree with the changes made to R6 and R7. | Yes | | No | We have the following comments on the VSL: 1. R3: There is a potential overlap between High and Severe. For an ATCID does not include “two or more” of the information items in R3, it could mean does not include all of the information items. This is the same condition as a Severe. We | We do not see the role of TOP in this standard. The TOP’s primary responsibility is to o<br>area in a reliable manner, and determine SOLs and where necessary, transmission tran<br>capabilities (where applicable). Given the established SOLs, TTCs, TFCs that are determ<br>planning, and the TTCs and TFCs determined by other entities such as the RCs, TPs an<br>different time frames, the TSP needs only to calculate ATCs (or AFCs) respecting these |

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| | | | | | | acceptable as revised | | Provider | By “no more limiting than” the assumptions used in planning of operations for the same time period, it would imply that the TOP and TSP may use less restrictive (or more liberal) assumptions. The results could be that the TTCs and ATCs are higher than the planned operational parameters, giving rise to potential unreliability. We do not see a problem with the previous wording of “consistent with”, and this should be reinstated. | | | | suggest to reword the High VSL to “does not include up to 2 of the information items in R3”; and the Severe VSL to “or its ATCID does not include 3 or more of the information described in R3”, or numbers along that line. 2. We do not agree with the VSLs for R6 and R7 for reasons noted above. | so, it should be able to select an ATC calculation method to suit its business model and the basis of the TTCs and TFCs that affect its service area. With this in mind, we sugge that the TSP be the one who selects the ATC method and R1 should be revised accordi be assumed that the TOP area and the TSP area are the same and hence the basis of t TSP's area may differ from one part to another. |
| | Individual | Alessia Dawes | Hydro One Networks | | | Yes - definitions are acceptable as revised | | Transmission Service Provider | There are 2 methodologies listed in R1. Are these the only two from which we have to choose? We suggest rewording the requirement to avoid this confusion by inserting the words "for example". In R6 and R7, we prefer the previous wording "consistent with" instead of "no more limiting" as the new wording may result in the use of less restrictive assumptions and hence give rise to potential unreliability. | Yes | | No | For the severe VSL for R2 keep consistent the wording as per the other levels. The Lower, Moderate, and High VSLs for R4 are missing the words "did not". | In requirement 8, if the 80 days grace period is to account for software outages then s else entities may interpret the requirement as applicable to outages other then softwa |
| | | | | | | | | | Modification to Requirement 1: Each Transmission Operator shall select a methodology for calculating ATC or AFC for each ATC Path or Flowgate for each time period identified in Requirements 2.1 - 2.3 for those Facilities within its Transmission Operators Area. Modifications to 2.2 Daily values for at least the next 31 calendar days (Following the 48 Hours specified in R2.1) Modification to 2.3 Monthly values for at least the next 12 months (Following the 31 Calendar days specified in R2.2) Modification to R3: Each TSP shall prepare and keep current an ATCID that includes the following information. (The Phrase "at a minimum" is unnecessary because the TSP | | | | | |

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| | Individual | Jason Shaver | American Transmission Company | | | No - one or more definitions needs revision - see comments | Capitalize "Existing Transmission Commitments" in the Available Transfer capability definition, since it is a defined term. We do not believe that the SDT has to provide a definition of ATCID. Requirement 3 outlines the specifics of ATCID and we find the definition unnecessary. The SDT should explain why this definition is necessary. | Transmission Operator | must comply with the sub-requirements. Any additional information is beyond the requirements and therefore not subject to NERC's audit.) Starting in Requirement 3.3 the phrase "transfer or Flowgate capability" is used. Does this phase equate to ATC and AFC where ATC is equal to transfer capability and AFC is equal to Flowgate capability? We would prefer that the SDT remain consistent and use the phrase "ATC or AFC if the phrases are equal. In Requirement 3.3 did the SDT mean "transfer or Flowgate capability" or "transfer of Flowgate capability"? The requirement currently uses the "of" word. In order to maintain a consistent use of the phrase "ATC or AFC" we suggest the following change to Requirement 3.6. "A description of how outages are considered in ATC or AFC calculations including:" The SDT should explain any disagreement with our suggested modification. R5 should be revised to delete the words "all of" to avoid being overly inclusive. R6 should be revised to "no more limiting than those used in the planning of operations." Modifications to R8: The TSP shall recalculate ATC or AFC on the following frequency, unless none of the calculated values identified in the ATC or AFC equations have changed. Question to R8.1: How will the 80 hours per calendar year be calculated? (Does a non-calculation period that is exempt in Requirement 8 count to the 80 hours?) R9 should be revised to eliminate "any" and "all" to avoid being overly inclusive: (1) delete the words "any" from "Within thirty calendar days of receiving a request by any | Yes | | Yes | | The first time that each abbreviation or acronym is introduced, the full terminology sho abbreviation or acronym in brackets (i.e. ATC, AFC, TTC, and TFC). The SDT should prc what would be the proposed effective data of this standard. FERC has justification over operators of the BPS and following their approval the standard would become "enforcea even in the US these standards will not become "enforceable" until all regulatory autho have approved this set of standards? If this is the case how would NERC insure such a |

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| | | | | | | | | | Transmission Service Provider..."; (2) delete the words "all" from "Unit commitments and order of dispatch, to include all designated network resources..."; (3) delete the words "Any" from the phrase "Any firm and non-firm adjustments..."; (4) delete the words "Any" from the phrase "Any other services that that impact ....."; (5) delete the word "all" from "Values of CBM and TRM and TTC for all ATC [paths or Flowgates."; (6) delete "any" from the phrase "any Flowgates considered by the Transmission Service Provider receiving the request..."; (7) delete the word "all" from the phrase "Values of TTC and ATC for all ATC Paths for those...". 5. Delete "all" and "any" in the Measures, the Compliance section, and the Violations Severity Levels to avoid being overly inclusive. | | | | | |
| | Individual | Rex McDaniel | Texas-New Mexico Power Company | | | No - one or more definitions needs revision - see comments | All schedules in ERCOT flow with no pre-defined paths and any congestion is mitigated by market mechanisms and/or verbal dispatch instructions from ERCOT (in the case of an emergency). Texas-New Mexico Power Company (TNMP) is concerned about the risk of ERCOT being found in non-compliance with the underlying standard due to the methodologies not being a part of the ERCOT market. Furthermore, TNMP believes that implementation of the prescribed methodologies would add no value to the ERCOT market | No Preference | | Yes | | Yes | | This standard should not apply to ERCOT for the reason expressed in question 1. |

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| | | | | | | | and could result in more system congestion. TNMP strongly suggests that this standard specify that it is not applicable to regions with a single control area and no defined ATC path(s). | | | | | | | |
| | Individual | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | | | No - one or more definitions needs revision - see comments | For the ERCOT region/market the concept of ATC, AFC are not applicable. It is suggested that the definition of ATC have some consideration for whether there is a required "commercial activity" for it in a region. | Transmission Operator | | | | | | As commented in Question #1, Brazos Electric does not believe that the application of would serve any reliability need or commercial market purpose. Therefore an exclusion requirements based on whether a TO/TOP operates soley in a single control area region |
| | | | | | | | The NYISO has continuing concerns with two of the revised definitions: (i) "ATC Path;" and (ii) "ATC." ATC Path: The NYISO previously expressed concern with the SDT's use of a new defined term "ATC Path" instead of the term "Posted Path" that was used in earlier versions of MOD-001 and is more consistent with the terminology used in FERC's OASIS posting regulations. The NYISO continues to be concerned that the proposed definition of "ATC Path" set forth in the latest version of proposed MOD-001 could, absent revision or clarification, subject the NYISO to potential penalties that would be inappropriate given the nature of its financial reservation system and the inapplicability | | | | | | | |

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| | | | | | | | of certain OASIS posting requirements to it. Specifically, as the NYISO has explained in previous comments, ATC serves a fundamentally different purpose and is calculated differently in New York, because there are no express physical transmission reservations and all desired uses of the grid are accommodated to the extent that customers are willing to pay congestion. FERC has expressly recognized that the NYISO's ATC postings are merely advisory projections that may be of some commercial benefit to customers but that they do not determine whether customers can obtain transmission service. The NYISO has also explained that there are no "Posted Paths" as that term is defined under FERC's OASIS regulations internal to the NYISO and that the NYISO is not required, both because of that fact, and because of FERC orders exempting the NYISO from certain OASIS regulations, to post ATC on its internal interfaces for periods further out than one day-ahead. The current draft of MOD-001 would define "ATC Path" as including both "Posted Paths" and "any other combination of Point of Receipt and Point of | | | | | | | |

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| | | | | | | Delivery for which Available Transfer Capability is calculated." The NYISO remains concerned that without clarification this definition could be interpreted in a way that would require the NYISO to post ATC for time periods further out than one day ahead when it is not required by FERC's regulations to make such postings and where such postings would serve no reliability purpose (because they have nothing to do with scheduling or "over-scheduling" long-term transactions.) Given the nature of the NYISO's financial reservation system, and the central role that the output of its day-ahead and real-time market software plays in its ATC calculations (see below), the NYISO would not have any meaningful information to post for periods further out than one day-ahead in any case. The NYISO therefore respectfully requests that the SDT either: (i) remove the defined term "ATC Path" and return to the use of "Posted Path" as that term is defined in FERC's OASIS regulations; or (ii) revise the term "ATC Path" as follows: "ATC Path: Any Posted Path or any other combination of | | The NYISO continues to agree with the ISO/RTO Council that the MOD standards extend into areas that should be covered and addressed by NAESB Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices, and not included in the NERC standards as reliability based requirements Nevertheless, to the extent that the SDT decides to keep such requirements in proposed MOD-001, the NYISO offers the following additional comments or R2, R8, and M2. R2 This requirement continues to reflect an assumption that all Transmission Service Providers are required under FERC's regulations to calculate and post ATC values for periods 48 hours, one month, and one year into the future. This is not true of the NYISO. Because of the nature of its financial reservation system, FERC has only required the NYISO to calculate and post ATCs for its internal interfaces for a period one day-ahead. The NYISO does not post and calculate, and given the nature of its system, cannot post and calculate, ATCs further out than one day ahead for those internal interfaces or for certain controllable lines that link the NYISO to neighboring Transmission Service Providers. Thus, as drafted, R2 would conflict with FERC orders and FERC approved tariff provisions excusing the NYISO from posting longer range ATCs. It would also require the NYISO to calculate and post ATCs that it cannot practically calculate given the nature of its system (under which ATC is determined primarily | | | | | |

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| | Individual | Rick Gonzales | New York Independent System Operator | | | No - one or more definitions needs revision - see comments | Point of Receipt and Point of Delivery for which Available Transfer Capability is calculated, provided, however, that interfaces or paths for which a Transmission Service Provider is not required under FERC's regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead shall not be considered to be ATC Paths" The NYISO's proposed revision would apply to few Transmission Service Providers, and thus would not undermine the proposed requirements or harm reliability. It would, however, be a very important accommodation to the NYISO that would prevent it from being subjected to inappropriate penalties under R1, R2, or R8. Available Transfer Capability ("ATC"): The proposed new definition of "ATC" does not appear to be flexible enough to accommodate the fundamentally different nature of ATC under the NYISO's FERC-approved financial reservation transmission model. As the NYISO has previously explained, a customer's ability to schedule transactions in the NYISO system is not limited by a pre-defined amount of ATC. In New York | Transmission Service Provider | by the output of the NYISO's day-ahead and real-time market software). If R2 is not modified, the NYISO would have to seek a modification (or waiver) from FERC to avoid being subject to penalties for non-compliance with a requirement that should not apply to it. The NYISO respectfully requests that the SDT address the problem by revising proposed R2 as follows: "Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the ATC methodology or methodologies selected by its Transmission Operator(s), except to the extent that the Transmission Service Provider is not required, under FERC's regulations, or as a result of FERC orders, to calculate and post ATC for periods further out than one day-ahead: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] R2.1. Hourly ATC values for at least the next 48 hours. R2.2. Daily ATC values for at least the next 31 calendar days. R2.3. Monthly ATC values for at least the next 12 months (months 2-13). In addition, the violation severity levels for these draft standards now have a graded implementation. Nevertheless, it may still be possible for multiple violations to result from a single unintended event. The NYISO requests that double counting of violations for a single event be eliminated by adding a new Item 6 to Section A of the proposed standard to establish this point. R8 The NYISO has previously asked the SDT to clarify or revise R8 so that Transmission Service Providers such as the NYISO that are not required to post monthly ATC values for internal interfaces (See the | Yes | | No | The NYISO agrees with the ISO/RTO Council comments on this issue. NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards now for the most part have a graded implementation, but the NYISO remains concerned regarding the possibility of multiple violations resulting from a single event. Therefore, the NYISO requests that double counting of violations for a single event be eliminated. A single event shall not result in multiple violations. |

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| | | | | | | | ATC is not, in the SDT's words, "a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses." Instead, ATC postings are really "advisory projections" calculated after the NYISO markets close, and transactions are scheduled, based on calculations performed by the NYISO's day-ahead and real-time market software. The fact that a posted ATC is zero does not mean that further commercial activity is precluded because the NYISO may redispatch its system to support additional transactions. A posted ATC value of zero simply indicates that there is congestion at a particular NYISO interface. FERC has granted the NYISO a number of waivers from its OASIS regulations that reflect these differences and has recognized that ATC is merely an "advisory projection" in New York. The NYISO therefore respectfully requests that the SDT accommodate the different nature of ATC under the NYISO's FERC-approved financial | NYISO's response to Question One, above) would not be subject to a requirement to recalculate such values on a weekly basis. Otherwise, R8 would effectively require the NYISO to conduct calculations that FERC has excused it from conducting and that would serve no reliability purpose under the NYISO's financial reservation transmission model. The NYISO therefore respectfully requests that the SDT revise R8 to to clearly establish that Transmission Service Providers need not recalculate ATC values that they are not required to calculate or post under FERC's regulations, or as a result of FERC orders M2 Consistent with the NYISO's comments on R2 and R8, and with past NYISO comments, NERC should revise M2 to clearly state that Transmission Service Providers need not provide evidence that they calculated ATCs that they are not required to calculate or post under FERC's regulations, or as a result of FERC orders | | | | | |

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| | | | | | | | transmission model by either: (i) deleting the proposed definition of ATC; or (ii) specifying that each Transmission Service Provider must include its definition of ATC in its ATCID (and expressly allowing entities such as the NYISO to have definitions that vary from the standard definition); or (iii) revising the definition as follows: "Available Transfer Capability (ATC): A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows, except with respect to Transmission Service Providers that employ FERC-approved financial reservation transmission models in which ATC serves as an advisory projection of potential transmission congestion." Again, the NYISO's proposed revision would not apply to | | | | | | | |

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| | | | | | | | many Transmission Service Providers, and thus would not undermine the proposed standard or harm reliability. It would, however, be a very important accommodation to the NYISO that would prevent it from being subjected to inappropriate penalties under R1, R2, R3.6, and R8. | | | | | | | |

# Standards Announcement

## Comment Period Opens
## April 16–May 15, 2008

**Now available at: http://www.nerc.com/~filez/standards/MOD-V0-Revision.html**

### Comment Period for Available Transfer Capability Standards (Project 2006-07) Posted for 30-day Comment Period April 16–May 15, 2008

The ATC Standard Drafting Team has posted the following five revised standards related to the determination of Available Transfer Capability (ATC) for a 30-day comment period through May 15, 2008. Each standard has its own implementation plan and has its own comment form.

MOD-001 — Available Transfer Capability — An "umbrella" standard that requires the selection of a methodology, the updating of values, and the sharing of procedures and data. Comment Form

MOD-008 — Transmission Reliability Margin — A standard that describes the calculation and use of TRM. Comment Form

MOD-028 — Area Interchange Methodology (Network Response ATC Methodology) — A standard that describes the calculation of TTC and ATC, as performed primarily in the Eastern Interconnection. Comment Form

MOD-029 — Rated System Path Methodology — A standard that describes the calculation of TTC and ATC, as performed primarily in the Western Interconnection. Comment Form

MOD-030 — Flowgate Methodology (Network Response Flowgate Methodology) — A standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC. Comment Form

These standards have been revised based on stakeholder comments from the initial ballot conducted March 3–12, 2008. The drafting team's responses to the comments submitted with the ballots for these standards are posted for stakeholder review. The drafting team is still working on revisions to MOD-004-1 — Capacity Benefit Margin, and will post its consideration of the comments submitted with the initial ballot of MOD-004 and the revised standard and implementation plan for comment at a later time.

### Standards Development Process

The NERC posting and balloting procedures are described in the *Reliability Standards Development Procedure Manual*, which contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 15, 2007.
6. SC Conducted an Initial Ballot of the standard from March 3–2, 2008

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR with consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| **1.** Posting for 30-day industry comment. | May 23, 2008 |
| **2.** Respond to Comments. | August 25, 2008 |
| **3.** Posting for 30-day Pre-Ballot Review. | August 26, 2008 |
| **4.** Initial Ballot. | September 25, 2008 |
| **5.** Respond to comments. | October 31, 2008 |
| **6.** Recirculation ballot. | November 1, 2008 |
| **7.** 30-day posting before board adoption. | August 26, 2008 |
| **8.** Board adoption. | November 13, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Generation Capability Import Requirement (GCIR):** The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.

**Capacity Benefit Margin Implementation Document (CBMID):** A document that describes the implementation of a Capacity Benefit Margin methodology.

## A. Introduction

1. **Title:** **Capacity Benefit Margin**
2. **Number:** **MOD-004-1**
3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.
4. **Applicability:**
   - **4.1.** Load-Serving Entities.
   - **4.2.** Resource Planners.
   - **4.3.** Transmission Service Providers.
   - **4.4.** Balancing Authorities.
   - **4.5.** Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM.
5. **Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard become effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

**R1.1.** The process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the Resource Planner associated with that Balancing Authority Area, may ensure that its need for Transmission capacity to be set aside as CBM will be reviewed and accommodated by the Transmission Service Provider to the extent Transmission capacity is available.

**R1.2.** The procedure and assumptions for establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate.

**R1.3.** The procedure for a Load-Serving Entity or Balancing Authority to use Transmission capacity set aside as CBM.

**R2.** The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area, and notify those entities of any changes to the CBMID prior to the effective date of the change. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.** Each Load-Serving Entity determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Using one of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R3.2.** Identifying expected import paths or source regions.

**R4.** Each Resource Planner determining the need for Transmission capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.1.** Using one of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R4.2.** Identifying expected import paths or source regions.

**R5.** At least every 13 months, the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be used for ATC or Available Flowgate Capability (AFC) calculations during the subsequent 13 months. This value shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Service Provider's area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Service Provider's area
- Any reserve margin or resource adequacy requirements for loads within the Transmission Service Provider's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R5.2.** Be allocated as follows:

- For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Service Provider

**R6.** At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used for planning purposes during the subsequent years two through ten. This value shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Planner's area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner's area
- Any reserve margin or resource adequacy requirements for loads within the Transmission Planner's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R6.2.** Be allocated as follows:

- For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner.

**R7.** Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the Transmission Service Provider's system of the amount of CBM set aside to meet their need. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R8.** Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the system being planned by the Transmission Planner of the amount of CBM set aside to meet their need. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R9.** The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide copies of the supporting data, including any models, used for determining CBM or allocating CBM over each ATC Path or Flowgate to the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

**R9.1.** Each of its associated Transmission Operators within 30 calendar days of their making a request for the data.

**R9.2.** To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within 30 calendar days of their making a request for the data.

**R10.** The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [*Violation Risk Factor: Lower*] [*Time Horizon: Same-day Operations*]

**R11.** When reviewing an Arranged Interchange using CBM, the Balancing Authority and Transmission Service Provider shall waive, within the bounds of reliable operation, any Real-time timing and ramping requirements. [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations*]

**R12.** The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an Energy Deficient Entity[1] under an EEA 2 if: [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations*]

**R12.1.** The CBM is available

**R12.2.** The EEA 2 is declared within the Balancing Authority Area of the Load-Serving Entity, and

**R12.3.** The Balancing Authority with the EEA 2 is located within the Transmission Service Provider's area.

## C. Measures

**M1.** Each Transmission Service Provider that maintains CBM shall produce its CBMID evidencing inclusion of all information specified in R1. (R1)

**M2.** Each Transmission Service Provider that maintains CBM shall have evidence (such as dated logs and data, copies of dated electronic messages, or other equivalent evidence) to show that it made the current CBMID available to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators specified in R2, and that prior to any change to the CBMID, it notified those entities of the change. (R2)

**M3.** Each Load-Serving Entity that determined a need for Transmission capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R3. (R3)

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[1] See Attachment 1-EOP-002-0 for definition.

**M4.** Each Resource Planner that determined a need for Transmission capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R4. (R4)

**M5.** Each Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established 13 months of CBM values consistent with the requirements in R5.1 and allocated the values consistent with the requirements in R5.2. (Note that CBM values may legitimately be zero.) (R5)

**M6.** Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established CBM values for years two through ten consistent with the requirements in R6.1 and allocated the values consistent with the requirements in R6.2. (Note that CBM values may legitimately be zero.) (R6)

**M7.** Each Transmission Service Provider that maintains CBM shall provide evidence (such as dated e-mail, data, or other records) that it notified the entities described in R7 of the amount of CBM set aside to meet their need. (R7)

**M8.** Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as e-mail, data, or other records) that it notified the entities described in R8 of the amount of CBM set aside to meet their need. (R8)

**M9.** Each Transmission Service Provider that maintains CBM and each Transmission Planner shall provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in R9. (R9)

**M10.** Each Load-Serving Entity and Balancing Authority shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time it requested to import energy using firm Transfer Capability set aside as CBM, they were in an EEA 2. (R10)

**M11.** Each Balancing Authority and Transmission Service Provider shall provide evidence (such as operating logs and tag data) that it waived Real-time timing and ramping requirements when approving an Arranged Interchange using CBM (R11)

**M12.** Each Transmission Service Provider that maintains CBM shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any Arranged Interchange meeting the criteria in R12. (R12)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority (CEA)

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Data Retention**

- The Transmission Service Provider that maintains CBM shall maintain its current, in force CBMID and any prior versions of the CBMID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Service Provider that maintains CBM shall maintain evidence to show compliance with R2, R5, R7, R9, and R12 for the most recent three calendar years plus the current year.
- The Load-Serving Entity shall each maintain evidence to show compliance with R3 and R10 for the most recent three calendar years plus the current year.
- The Resource Planner shall each maintain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- The Transmission Planner shall maintain evidence to show compliance with R6, R8, and R9 for the most recent three calendar years plus the current year.
- The Balancing Authority shall maintain evidence to show compliance with R10 and R11 for the most recent three calendar years plus the current year.
- The Transmission Service Provider shall maintain evidence to show compliance with R11 for the most recent three calendar years plus the current year.
- If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

**None.**

## Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made within the last three months. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago.<br>**OR**<br>The CBM maintaining Transmission Service Provider's CBMID does not address one of the sub requirements. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago.<br>**OR**<br>The CBM maintaining Transmission Service Provider's CBMID does not address two of the sub requirements. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than twelve months ago.<br>**OR**<br>The Transmission Service Provider that maintains CBM does not have a CBMID;<br>**OR**<br>The CBM maintaining Transmission Service Provider's CBMID does not address three of the sub requirements. |
| R2. | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID after a change was made but not more than 30 calendar days after a change was made. | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID 30 or more calendar days but not more than 60 calendar days after a change was made. | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID 60 or more calendar days but not more than 90 calendar days after a change was made.<br>**OR**<br>The Transmission Service Provider that maintains CBM made available the CBMID to some, but not all, of the entities specified in R2. | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID more than 90 calendar days after a change was made.<br>**OR**<br>The Transmission Service Provider that maintains CBM made available the CBMID to none of the entities specified in R2. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | | The Load-Serving Entity did not use one of the methods described in R3.1<br>**OR**<br>The Load-Serving Entity did not identify paths or regions as described in R3.2 | | The Load-Serving Entity did not use one of the methods described in R3.1<br>**AND**<br>The Load-Serving Entity did not identify paths or regions as described in R3.2 |
| R4 | | The Resource Planner did not use one of the methods described in R4.1<br>**OR**<br>The Resource Planner did not identify paths or regions as described in R4.2 | | The Resource Planner did not use one of the methods described in R4.1<br>**AND**<br>The Resource Planner did not identify paths or regions as described in R4.2 |
| R5. | The Transmission Service Provider that maintains CBM established CBM more than 13 months, but not more than 16 months, after the last time the values were established. | The Transmission Service Provider that maintains CBM established CBM more than 16 months, but not more than 19 months, after the last time the values were established.<br>**OR**<br>The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1<br>**OR**<br>The Transmission Service Provider that maintains CBM did not base the allocation on one or more paths or regions as described in R5.2 | The Transmission Service Provider that maintains CBM established CBM more than 19 months, but not more than 22 months, after the last time the values were established. | The Transmission Service Provider that maintains CBM established CBM more than 22 months after the last time the values were established.<br>**OR**<br>The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available, and did not base the allocation on one or more paths or regions as described in R5.2 |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R6. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM more than 13 months, but not more than 16 months, after the last time the values were established. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM more than 16 months, but not more than 19 months, after the last time the values were established.<br>**OR**<br>The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1<br>**OR**<br>The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not base the allocation on one or more paths or regions as described in R6.2 | The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM more than 19 months, but not more than 22 months, after the last time the values were established. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM more than 22 months after the last time the values were established.<br>**OR**<br>The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1 that was available, and did not base the allocation on one or more paths or regions as described in R6.2 |
| R7. | The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days. | The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days. | The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days.<br>**OR**<br>The Transmission Service Provider that maintains CBM notified some, but not all, of the | The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 75 or more days,<br>**OR**<br>The Transmission Service Provider that maintains CBM notified none all the entities as required. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | entities as required. | |
| R8. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days.<br>**OR**<br>The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified some, but not all, of the entities as required. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 75 or more days,<br>**OR**<br>The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified none of the entities as required. |
| R9. | The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 30, but not more than 45, days after the submission of the request. | The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 45, but not more than 60, days after the submission of the request. | The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 60, but not more than 75, days after the submission of the request.<br>**OR**<br>The Transmission Service Provider or Transmission Planner provided some, but not all, of the requesters specified in R9 with the supporting data, including models, used to allocate CBM. | The Transmission Service Provider or Transmission Planner provided a requester specified in R9 with the supporting data, including models, used to allocate CBM more than 75 days after the submission of the request.<br>**OR**<br>The Transmission Service Provider or Transmission Planner provided none of the requesters specified in R9 with the supporting data, including models, used to allocate CBM. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R10. | N/A | N/A | N/A | A Load-Serving Entity or Balancing Authority requested to schedule energy over CBM while not in an EEA 2 or higher. |
| R11. | N/A | N/A | N/A | A Balancing Authority or Transmission Service Provider denied an Arranged Interchange using CBM based on timing or ramping requirements without a reliability reason to do so. |
| R12. | N/A | N/A | N/A | The Transmission Service Provider failed to approve an Arranged Interchange for CBM that met the criteria described in R12 without a reliability reason to do so. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

### Development Steps Completed:

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007
5. SDT posted second draft for comment from October 31–December 15, 2007.
6. SC Conducted an Initial Ballot of the standard from March 3–12, 2008

### Description of Current Draft:

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR with consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Oder 890, and Order 890-A.

### Future Development Plan:

| Anticipated Actions | Anticipated Date |
|---|---|
| **1.** Posting for 30-day industry comment. | May 22, 2008 |
| **2.** Respond to Comments. | August 25, 2008 |
| **3.** Posting for 30-day Pre-Ballot Review. | August 26, 2008 |
| **4.** Initial Ballot. | September 25, 2008 |
| **5.** Respond to comments. | October 31, 2008 |
| **6.** Recirculation ballot. | November 1, 2008 |
| **7.** 30-day posting before board adoption. | August 26, 2008 |
| **8.** Board adoption. | November 13, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Generation Capability Import Requirement (GCIR):** The amount of generation capability from external sources ~~requested~~ identified by a Load-Serving Entity (LSE) ~~(or group of LSEs with an aggregated need for Capacity Benefit Margin)~~ or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.

**Capacity Benefit Margin Implementation Document (CBMID):** A document that describes the implementation of a Capacity Benefit Margin methodology.

~~**Planned Resource Sharing Group (PRSG):** A group of Load-Serving Entities who have agreed to jointly meet their resource adequacy requirements.~~

## A. Introduction

**1. Title:** **Capacity Benefit Margin**

**2. Number:** **MOD-004-1**

**3. Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.

**4. Applicability:**

~~**4.1.Functional Entity:**~~

**~~4.1.1~~4.1.** ~~Load Serving~~Load-Serving Entities~~y~~.

**4.2.** ~~Planned~~Resource ~~Sharing Group~~ Planners.

**4.3.** Transmission Service Providers. ~~that maintain CBM.~~

**~~4.1.4~~4.4.** Balancing Authorities.~~y.~~

**~~4.1.5~~4.5.** Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM.

~~**5.Facility Limitations/Specifications:**~~

~~5.1.None.~~

**~~6.~~5.** **Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard become effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

**R1.1.** ~~Its procedure for a Load-Serving Entity or Planned Resource Sharing Group within a Balancing Authority associated with the Transmission Service Provider to request the Generation Capability Import Requirement (GCIR) including the disposition and handling of deficient requests.~~ The process through which a ~~Load Serving~~Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the Resource Planner associated with that Balancing Authority Area, may ensure that its need for ~~t~~Transmission capacity to be set aside as CBM will be reviewed and accommodated by the Transmission Service Provider to the extent ~~t~~Transmission capacity is available.

**R1.2.** ~~Its~~ The procedure and assumptions for ~~setting~~ establishing CBM for each Available Transfer Capability (ATC) Path or Flowgate ~~based on Load-Serving Entity or Planned Resource Sharing Group GCIR~~.

**R1.3.** ~~Its~~ The procedure for a ~~Load Serving~~Load-Serving Entity or Balancing Authority to ~~request the~~ use ~~of Transfer Capability~~~~t~~Transmission capacity set aside as CBM.

~~**R2.** A statement of whether the Transmission Service Provider allows ATC or AFC to be less than zero due to CBM.~~

~~**R3.**~~The Transmission Service Provider that maintains CBM shall make available its current CBMID ~~and any changes to the CBMID~~ to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area, and notify those entities of any changes to the CBMID prior to the effective date of ~~a~~ the change. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

~~**R4.** A Load-Serving Entity or Planned Resource Sharing Group that wants Transfer Capability to be set aside in the form of CBM shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]~~

~~**R5.** Submit an annual GCIR request to the Transmission Service Provider and Transmission Planner per the specifications in the CBMID that includes:~~

~~**R6.** The GCIR, specifying:~~

~~**R7.** A monthly GCIR value for each month for the next 24 months. If monthly values are not a requirement as per the applicable reserve margin and resource adequacy requirements documented in R3.1.2, a yearly GCIR value for the current and following year will be sufficient .~~

~~**R8.** An annual GCIR value for each subsequent year for each Balancing Authority or Posted Path not to exceed 10 years into the future.~~

~~**R9.** The location of the load served by the GCIR (e.g., Balancing Authority, zones, markets …).~~

~~**R10.** Assumed external resources (e.g., Balancing Authority(ies), specific generators, markets …) from which generation supporting each GCIR value of 3.1.1.1 and 3.1.1.2 will be supplied or the specific ATC Paths to be used for import of the generation supporting the GCIR.~~

~~**R11.** Identification of all applicable reserve margin and resource adequacy requirements, and the entity(ies) responsible for establishing them, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities.~~

~~**R12.** The process and periodicity of calculating or recalculating GCIR if the entities specified in R3.1.2 require calculating GCIR on a frequency different than specified in R3.1.1~~

~~**R13.** A summary of the results of resource studies performed to determine the amount of the request, not to include confidential information.~~

~~**R14.** All resource studies (and supporting information) performed to determine the amount of the request.~~

~~**R15.**Every thirty-one calendar days, each Load Serving Entity or Planned Resource Sharing Group shall adjust its GCIR request, if necessary per 3.1.1 or 3.1.2.1, to reflect any incremental increase or decrease in required GCIR by either simple adjustment or through recalculation. .~~

~~**R3.3.**~~**R2.** ~~Base the request provided per R3.1 on studies conducted in accordance with verifiable historical, state, regional transmission organization or regional entity criteria.~~

**R3.** Each ~~Load Serving~~Load-Serving Entity determining the need for Transmission ~~C~~capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Using one of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R3.2.** Identifying expected import paths or source regions.

**R4.** Each Resource Planner determining the need for Transmission ~~C~~capacity to be set aside as CBM for imports into a Balancing Authority Area shall determine that need by: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.1.** Using one of the following to determine the GCIR:

- Loss of Load Expectation (LOLE) studies
- Loss of Load Probability (LOLP) studies
- Deterministic risk-analysis studies
- Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R4.2.** Identifying expected import paths or source regions.

~~**R4.**~~**R5.** At least every 13 months,~~Within fourteen calendar days of receiving a request or change to a GCIR request that meets the requirements defined in R3.1, the Transmission Service Provider shall set the CBM for the next 13 months requested as described in R3.1 as follows:~~ the Transmission Service Provider that maintains CBM shall establish a CBM value for each ATC Path or Flowgate to be used for ATC or Available Flowgate Capability (AFC) calculations during the subsequent 13 months. This value shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by ~~Load Serving~~Load-Serving Entities for loads within the Transmission Service Provider's area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Service Provider's area
- Any reserve margin or resource adequacy requirements for loads within the Transmission Service Provider's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R5.2.** Be allocated as follows:

- For ATC Paths, based on the expected import paths or source regions provided by ~~Load Serving~~Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by ~~Load Serving~~Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Service Provider

~~**R17.1.**~~At least every 13 months, t~~Determine the amount of CBM (for use in R4.2) for each request by using one of the following:~~

~~**R17.1.1.**For the Area Interchange Methodology and the Rated System Path Methodology, using the requested Generation Capability Import Requirement for the appropriate ATC Path(s)~~

~~**R17.1.2.**For the Flowgate Methodology, determining the significant impacts of each request on each Flowgate~~

~~17.1.2.1.Determine impacts of a request by multiplying the requested GCIR by the Distribution Factor for the import relative to the Flowgate or model the GCIR explicitly in the AFC model per R3.1.1.3 and R3.1.1.4.~~

~~**R17.2.**For the Area Interchange Methodology and the Rated System Path Methodology, set CBM for each ATC Path equal to the sum of all requests such that all requests can be met simultaneously or all firm ATC has been allocated to CBM as follows:~~

~~**R17.2.1.**If the situation exists where there is insufficient capability on the ATC Path to satisfy the sum of all GCIR requests and the Transmission Service Provider, per R1.4, does not allow ATC to be less than zero, then the Transmission Service Provider shall set the CBM such that the monthly ATCs equal zero~~

~~**R17.2.2.**If the situation exists where there is insufficient capability on the ATC Path to satisfy the sum of all GCIR requests and the Transmission Service Provider, per R1.4, allows the ATC to be less than zero, then the Transmission Service Provider shall set the CBM equal to the sum of the requested GCIR for that ATC Path.~~

~~**R17.3.**For the Flowgate Methodology set CBM for each Flowgate equal to the sum of all requests on that Flowgate such that all requests can be met simultaneously or all firm ATC has been allocated to CBM as follows:~~

~~**R17.3.1.**If the situation exists where there is insufficient Flowgate AFC to satisfy the sum of all GCIR requests and the Transmission Service Provider, per R1.4, does not allow the Flowgate AFC to be less than zero, then the Transmission Service Provider shall set the CBM such that the monthly Flowgate AFCs equal zero~~

~~**R17.3.2.**If the situation exists where there is insufficient Flowgate AFC to satisfy the sum of all GCIR requests and the Transmission Service Provider, per R1.4, allows the Flowgate AFC to be less than zero, then the Transmission Service Provider shall set the CBM equal to the sum of the requested GCIR for that Flowgate.~~

**~~R5.~~R6.** ~~Within sixty calendar days of receiving a request or change to a GCIR request that meets the requirements defined in R3.1, the Transmission Planner shall:~~he Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used for planning purposes during the subsequent years ~~2~~two through ~~10~~ten. This value shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** Reflect consideration of each of the following if available:

- Any studies (as described in R3.1) performed by ~~Load Serving~~Load-Serving Entities for loads within the Transmission Planner's area
- Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner's area
- Any reserve margin or resource adequacy requirements for loads within the Transmission Planner's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability Organizations, or regional entities

**R6.2.** Be allocated as follows:

- For ATC Paths, based on the expected import paths or source regions provided by ~~Load Serving~~Load-Serving Entities or Resource Planners
- For Flowgates, based on the expected import paths or source regions provided by ~~Load Serving~~Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner.

**R7.** Less than 31 calendar days after the establishment of CBM, the Transmission Service Provider that maintains CBM shall notify all the ~~Load Serving~~Load-Serving Entities and Resource Planners that determined they had a need for CBM on the Transmission Service Provider's system of the amount of CBM set aside to meet their need. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R8.** Less than 31 calendar days after the establishment of CBM, the Transmission Planner shall notify all the ~~Load Serving~~Load-Serving Entities and Resource Planners that determined they had a need for CBM on the system being planned by the Transmission

Planner of the amount of CBM set aside to meet their need. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

~~R5.1.As per R3.1.1.3 and R3.1.1.4, model the GCIR explicitly in the ATC/AFC model or use the CBM calculated using requirements R4.1 through R4.3 for all years requested beyond 13 months not to exceed 10 years~~

~~R5.2.If so requested, provide the Transmission Service Provider with the following:~~

~~R5.2.1.The total amount of CBM for each ATC Path or Flowgate on the Transmission Service Provider's system in each of the years specified in the original CBM request not to exceed 10 years.~~

~~R5.2.2.If less than the sum of all requests was established as the CBM for any period, for each ATC Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the years specified in the original request not to exceed 10 years.~~

~~**R19.**Within seven calendar days of the determination of CBM as described in R4 or R5, the Transmission Service Provider shall provide each Load-Serving Entity or Planned Resource Sharing Group that requested CBM and the Balancing Authority hosting its (their) load with a report that includes: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]~~

~~**R19.1.**The total amount of CBM for each ATC Path or Flowgate on the Transmission Service Provider's system in each of the months or years specified in the original request.~~

~~**R19.2.**If less than the sum of all requests was established as the CBM for any period:~~

~~- For each ATC Path or Flowgate, a list of the values of each GCIR used to set the CBM for each of the months and years specified in the original request~~

~~- The option to pursue alternatives, including expansion, with the Transmission Service Provider.~~

**~~R7.~~R9.** The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide copies of the supporting data, including any models, used for determining CBM or allocating CBM over each ATC Path or Flowgate to the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Long-term Planning*]

**~~R7.1.~~R9.1.** Each of its associated Transmission Operators within ~~thirty~~ 30 calendar days of their making a request for the data.

**~~R7.2.~~R9.2.** To any Transmission Service Provider, Reliability Coordinator, Transmission Planner, Resource Planner, or Planning Coordinator within ~~thirty~~ 30 calendar days of their making a request for the data.

**~~R8.~~R10.** The Load-Serving Entity or Balancing Authority ~~that wants to schedule energy over firm Transfer Capability set aside as CBM shall submit an Arranged Interchange, and~~ shall ~~not~~ request to ~~schedule~~ import energy over firm Transfer Capability set aside as CBM only ~~unless~~ when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [*Violation Risk Factor: Lower*] [*Time Horizon: Same-day Operations*]

**~~R9.~~R11.** When reviewing an Arranged Interchange using CBM, the Balancing Authority and Transmission Service Provider shall waive, within the bounds of reliable operation, any ~~real~~Real-time timing and ramping requirements. [*Violation Risk Factor: ~~Lower~~Medium*] [*Time Horizon: Same-day Operations*]

**~~R10.~~R12.** The Transmission Service Provider that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an Energy Deficient Entity[1] under an EEA 2 if: [*Violation Risk Factor: Medium*] [*Time Horizon: Same-day Operations*]

**R12.1.** The CBM is available

**R12.2.** The EEA 2 is declared within the Balancing Authority Area of the ~~Load Serving~~Load-Serving Entity, and

**R12.3.** The Balancing Authority with the EEA 2 is located within the Transmission Service Provider's area.

**Measures~~the CBM is available. [Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]~~**

[1] See Attachment 1-EOP-002-0 for definition.

## C. ~~Measures~~

**M1.** Each Transmission Service Provider that maintains CBM shall produce its CBMID evidencing inclusion of all information specified in R1. (R1)

**M2.** Each Transmission Service Provider that maintains CBM shall have evidence (such as dated logs and data, copies of dated electronic messages, or other equivalent evidence) to show that ~~prior to the effective date of a change to its CBMID,~~ it made the current CBMID available to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, and Planning Coordinators specified in R2, and that prior to any change to the CBMID, it notified those entities of the change. (R2)

**M3.** Each Load-Serving Entity ~~or Planned Resource Sharing Group that wants CBM shall provide a copy of its GCIR request with the supporting information specified in R3.1 to show that it is compliant with R3.1.~~that determined a need for Transmission ~~C~~capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R3. (R3)

**M4.** Each Resource Planner that determined a need for Transmission ~~C~~capacity to be set aside as CBM shall provide evidence (including studies and/or requirements) that it met the criteria in R4. (R4)

~~**M4.**Each Load-Serving Entity or Planned Resource Sharing Group that requests changes to its GCIR as per R3.2 shall provide dated copies of its updated GCIR along with studies or documentation of the changes that support its request; such as Transmission Service Requests, generator outage reports, and load-forecast changes that affect its resource adequacy requirements documented in R3.1.2. (R3).~~

~~**M5.**Each Load-Serving Entity or Planned Resource Sharing Group that wants CBM shall provide evidence (such as studies, historical data, copies of state or regional transmission organization reliability criteria, regional generation reliability criteria or other equivalent evidence) that it has based its GCIR request on verifiable historical, state, regional transmission organization, or regional generation reliability criteria in accordance with R3.3. (R3)~~

~~**M6.**~~**M5.** Each Transmission Service Provider that maintains CBM shall provide evidence ~~including copies of GCIR requests and requests for GCIR changes and other evidence such as copies of the actual computations to set CBM, or other equivalent evidence to show that CBM for the months requested as described in R3.1.1 has been established using the process described in R4.~~(such as studies, requirements, and dated CBM values) that it established 13 months of CBM values consistent with the requirements in R5.1 and allocated the values consistent with the requirements in R5.2. (Note that CBM values may legitimately be zero.) (~~R4~~R5)

**M6.** Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as studies, requirements, and dated CBM values) that it established CBM values for years ~~2~~two through ~~10~~ten consistent with the requirements in R6.1 and allocated the values consistent with the requirements in R6.2. (Note that CBM values may legitimately be zero.) (R6)

**M7.** Each Transmission Service Provider that maintains CBM shall provide evidence (such as dated e-mail, data, or other records) that it notified the entities described in R7 of the amount of CBM set aside to meet their need. (R7)

**M8.** Each Transmission Planner with an associated Transmission Service Provider that maintains CBM shall provide evidence (such as e-mail, data, or other records) that it notified the entities described in R8 of the amount of CBM set aside to meet their need. (R8)

~~**M7.**Each Transmission Planner shall provide evidence including copies of GCIR requests and requests for GCIR changes and other evidence (such as written documentation of studies and supporting study models that model base loadflow, copies of actual computations to set CBM, or other equivalent evidence) to show that the GCIR has been used to either model GCIR or calculate as per the process described in R5. (R5)~~

~~**M8.**Each Transmission Service Provider shall provide copies of the reports sent to Load-Serving Entities and Balancing Authorities along with other evidence (such as logs and data, copies of electronic messages, or other equivalent evidence) to show that within seven calendar days of the determination of CBM, a report meeting the requirements described in R6 was provided as specified. (R6).~~

**M9.** Each Transmission Service Provider that maintains CBM and each Transmission Planner shall ~~each~~ provide evidence including copies of dated requests for data supporting the calculation of CBM along with other evidences such as copies of electronic messages or other evidence to show that it provided the required entities with copies of the supporting data, including any models, used for allocating CBM as specified in ~~R7~~R9. (~~R7~~R9)

**M10.** Each Load-Serving Entity ~~or~~and Balancing Authority ~~that scheduled energy over firm Transfer Capability set aside as CBM~~ shall provide evidence (such as logs, copies of tag data, or other data from its Reliability Coordinator) that at the time ~~they~~ it requested ~~the~~ to import energy using~~schedule using~~ firm Transfer Capability set aside as CBM~~CBM~~, they were in an EEA 2. (~~R8~~R10)

**M11.** Each Balancing Authority and Transmission Service Provider shall provide evidence (such as operating logs and tag data) that it waived ~~real~~Real-time timing and ramping requirements when approving an Arranged Interchange using CBM (~~R9~~R11)

**M12.** Each Transmission Service Provider that maintains CBM shall provide evidence including copies of CBM values along with other evidence (such as tags, reports, and supporting data) to show that it approved any Arranged Interchange ~~using CBM for any Energy Deficient Entity[2] where the total CBM available was greater than the amount of CBM requested in the Arranged Interchange~~meeting the criteria in R12. (~~R10~~R12)

## D. Compliance

### 1. Compliance Monitoring Process

[2] See Attachment 1-EOP-002-0 for definition.

**1.1. Compliance Enforcement Authority (CEA)**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Data Retention**

- The Transmission Service Provider that maintains CBM shall maintain its current, in force CBMID and any prior versions of the CBMID that were in force since the last compliance audit to show compliance with R1~~1~~.
- The Transmission Service Provider that maintains CBM shall maintain evidence to show compliance with R2, ~~R2, R4, R6, R7~~R5, ~~and R10~~ R7, R9, and R12 for the most recent three calendar years plus the current year.
- The Load-Serving Entity ~~and Planned Resource Sharing Group~~ shall each maintain evidence to show compliance with R3~~,~~ and R~~8~~10 for the most recent three calendar years plus the current year.
- The Resource Planner shall each maintain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- The Transmission Planner shall maintain evidence to show compliance with ~~R5~~ R6, R8, and ~~R7~~ R9 for the most recent three calendar years plus the current year.
- The Balancing Authority shall maintain evidence to show compliance with ~~R9~~ R10 and R11 for the most recent three calendar years plus the current year.
- The Transmission Service Provider shall maintain evidence to show compliance with R11 for the most recent three calendar years plus the current year.
- If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

### 1.5. Additional Compliance Information

**None.**

## ~~2.~~Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made within the last three months. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than three, but not more than six, months ago.<br>**OR**<br>The CBM maintaining Transmission Service Provider's CBMID does not address~~es~~ one of the sub requirements. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than six, but not more than twelve, months ago.<br>**OR**<br>The CBM maintaining Transmission Service Provider's CBMID does not address two of the sub requirements. | The Transmission Service Provider that maintains CBM has a CBMID that does not incorporate changes that have been made more than twelve months ago.<br>**OR**<br>The Transmission Service Provider that maintains CBM does not have a CBMID;<br>**OR**<br>The CBM maintaining Transmission Service Provider's CBMID does not address three ~~or more~~ of the sub requirements. |
| R2. | The Transmission Service Provider that maintains CBM ~~makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator~~ notifies one or more of the entities specified in R2 of a change in the CBM ID ~~14 or more calendar days~~after a change was made but not more than 30 calendar days after a change was made. | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID ~~makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator~~ 30 or more calendar days but not more than 60 calendar days after a change was made. | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID ~~makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator~~ 60 or more calendar days but not more than 90 calendar days after a change was made.<br>**OR** | The Transmission Service Provider that maintains CBM notifies one or more of the entities specified in R2 of a change in the CBM ID ~~makes available the CBMID and any changes to the CBMID to the Transmission Operator, Transmission Service Provider, Reliability Coordinator, Transmission Planner, and Planning Coordinator~~ more than 90 calendar days after a change was made.<br>**OR**<br>The Transmission Service |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | The Transmission Service Provider that maintains CBM made available the CBMID to some, but not all, of the entities specified in R2. | Provider that maintains CBM made available the CBMID to none of the entities specified in R2. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | ~~The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2.~~ | The ~~Load Serving~~Load-Serving Entity ~~or Planned Reserve Sharing Group desiring CBM did not submit the information required by any one of the following: R3.1.2, R3.1.3, or R3.1.4.~~<br>~~**OR**~~<br>~~The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 20MW or 10%, whichever is smaller, and not more than 30MW or 20%, whichever is smaller.~~ did not use one of the methods described in R3.1<br>**OR**<br>The ~~Load Serving~~Load-Serving Entity did not identify paths or regions as described in R3.2 | ~~The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit the information two or more of the following: R3.1.2, R3.1.3, or R3.1.4.~~<br>~~**OR**~~<br>~~The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 30MW or 20%, whichever is smaller, and not more than 40MW or 30%, whichever is smaller.~~ | ~~The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not include one or more of the items specified in R3.1.1 in its request.~~<br>~~**OR**~~<br>~~The Load Serving Entity or Planned Reserve Sharing Group desiring CBM did not submit any of the information described in R3.1.2, R3.1.3, or R3.1.4.~~<br>~~**OR**~~<br>~~The Load Serving Entity or Planned Reserve Sharing Group did not update its request for CBM, or indicate that no update was needed, as described in R3.2, and their Generation Capability Import Requirement had changed by more than 40MW or 30%, whichever is smaller.~~<br>~~**OR**~~<br>~~The Load Serving Entity or Planned Reserve Sharing Group requested GCIR greater than its needs for imports to meet reserve margin or resource adequacy requirements (not to include the incremental power flows from reserve sharing requirements), and the~~ |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | ~~additional GCIR requested was more than 10MW in excess of the needed amount.~~ The ~~Load Serving~~Load-Serving Entity did not use one of the methods described in R3.1<br>**AND**<br>The ~~Load Serving~~Load-Serving Entity did not identify paths or regions as described in R3.2 |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R4 | | The Resource Planner did not use one of the methods described in R4.1 **OR** The Resource Planner did not identify paths or regions as described in R4.2 | | The Resource Planner did not use one of the methods described in R4.1 **AND** The Resource Planner did not identify paths or regions as described in R4.2 |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R4~~R 5. | ~~N/A~~The Transmission Service Provider that maintains CBM established CBM more than 13 months, but not more than 16 months, after the last time the values were established. | The Transmission Service Provider that maintains CBM established CBM more than 16 months, but not more than 19 months, after the last time the values were established.<br>**OR**<br>The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1<br>**OR**<br>The Transmission Service Provider that maintains CBM did not base the allocation on one or more paths or regions as described in R5.2~~N/A~~ | The Transmission Service Provider that maintains CBM established CBM more than 19 months, but not more than 22 months, after the last time the values were established.<br>~~The Transmission Service Provider set CBM for the months requested as described in R4 more than 14, but not more than 30 calendar days after receiving a request for CBM.~~<br>~~**OR**~~<br>~~The Transmission Service Provider did not follow the process described in R4.~~ | The Transmission Service Provider that maintains CBM established CBM more than 22 months after the last time the values were established.<br>**OR**<br>The Transmission Service Provider that maintains CBM did not consider one or more of the items described in R5.1 that was available, and did not base the allocation on one or more paths or regions as described in R5.2~~The Transmission Service Provider set CBM for the months requested as described in R4 more than 30 calendar days after receiving a request for CBM.~~<br>~~**OR**~~<br>~~The Transmission Service Provider did not follow the process described in R4 and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met.~~ |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R5~~R 6. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM more than 13 months, but not more than 16 months, after the last time the values were established.<br>~~N/A~~ | The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM more than 16 months, but not more than 19 months, after the last time the values were established.<br>**OR**<br>The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1<br>**OR**<br>The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not base the allocation on one or more paths or regions as described in R6.2~~N/A~~ | The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM more than 19 months, but not more than 22 months, after the last time the values were established.<br>~~The Transmission Planner set CBM for the years requested as described in R5 more than 60, but not more than 120, calendar days after receiving a request for CBM.~~<br>~~**OR**~~<br>~~The Transmission Planner did not follow the process described in R5.~~ | The Transmission Planner with an associated Transmission Service Provider that maintains CBM established CBM more than 22 months after the last time the values were established.<br>**OR**<br>The Transmission Planner with an associated Transmission Service Provider that maintains CBM did not consider one or more of the items described in R6.1 that was available, and did not base the allocation on one or more paths or regions as described in R6.2~~The Transmission Planner set CBM for the years requested as described in R5 more than 120 calendar days after receiving a request for CBM.~~<br>~~**OR**~~<br>~~The Transmission Planner did not follow the process described in R5, and the resource adequacy requirements of one or more Load Serving Entities requesting CBM were not met.~~ |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R6~~R7. | The Transmission Service Provider ~~provided the report to the requesting entities in more than 7 calendars days but not more than 9 calendar days of determining the CB~~ that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days.~~M~~ | The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days.~~The Transmission Service Provider provided the report to the requesting entities in 9 or more calendar days but not more than 14 calendar days of determining CBM~~ | The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days.<br>**OR**<br>The Transmission Service Provider that maintains CBM notified some, but not all, of the entities as required.~~The Transmission Service Provider provided the report to the requesting entities in 14 or more calendar days but not more than 22 calendar days of determining CBM~~ | The Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 75 or more days, ~~The Transmission Service Provider provided the report to the requesting entities 22 or more calendar days after determining CBM or did not provide the report.~~<br>**OR**<br>The Transmission Service Provider that maintains CBM notified none all the entities as required. |
| R8. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 31 or more days, but less than 45 days. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 45 or more days, but less than 60 days. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 60 or more days, but less than 75 days.<br>**OR**<br>The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified some, but not all, of the entities as required. | The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified all the entities as required, but did so in 75 or more days,<br>**OR**<br>The Transmission Planner with an associated Transmission Service Provider that maintains CBM notified none of the entities as required. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R7~~R 9. | The Transmission Service Provider or Transmission Planner ~~did not provide~~provided a requester specified in ~~R5~~ R9 with the supporting data, including models, used to allocate CBM ~~in~~ more than ~~seven~~30, but not more than ~~fourteen~~45, days after the submission of the request. | The Transmission Service Provider or Transmission Planner ~~did not provide~~provided a requester specified in ~~R5~~ R9 with the supporting data, including models, used to allocate CBM ~~in~~ more than ~~fourteen~~45, but not more than ~~thirty~~60, days after the submission of the request. | The Transmission Service Provider or Transmission Planner ~~did not provide~~provided a requester specified in ~~R5~~ R9 with the supporting data, including models, used to allocate CBM more than ~~thirty~~60, but not more than ~~sixty~~75, days after the submission of the request.<br>**OR**<br>The Transmission Service Provider or Transmission Planner provided some, but not all, of the requesters specified in R9 with the supporting data, including models, used to allocate CBM. | The Transmission Service Provider or Transmission Planner ~~did not provide~~provided a requester specified in ~~R5~~ R9 with the supporting data, including models, used to allocate CBM more than ~~sixty~~ 75 days after the submission of the request.<br>**OR**<br>The Transmission Service Provider or Transmission Planner provided none of the requesters specified in R9 with the supporting data, including models, used to allocate CBM. |
| ~~R8~~R 10. | N/A | N/A | N/A | A ~~Load Serving~~Load-Serving Entity or Balancing Authority requested to schedule energy over CBM while not in an EEA 2 or higher. |
| ~~R9~~R 11. | N/A | N/A | N/A | A Balancing Authority or Transmission Service Provider denied an Arranged Interchange using CBM based on timing or ramping requirements without a reliability reason to do so. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| ~~R10~~ R12. | N/A | N/A | N/A | The Transmission Service Provider failed to approve an Arranged ~~i~~Interchange for CBM that met the criteria described in R12 without a reliability reason to do so. ~~submitted by an Energy Deficient Entity under an EEA2 when CBM was available."~~ |

# Standards Announcement

## Comment Period Opens
## May 23–June 23, 2008

**Now available at: http://www.nerc.com/~filez/standards/MOD-V0-Revision.html**

### Comment Period for MOD-004-1 — Capacity Benefit Margin (Project 2006-07) Posted for 30-day Comment Period

The ATC Standard Drafting Team has posted the fourth draft of MOD-004-1 – Capacity Benefit Margin, standard and associated implementation plan for a 30-day comment period through June 23, 2008.

This standard has been revised based on stakeholder comments submitted with the initial ballot conducted March 3-12, 2008. The drafting team's responses to the comments submitted with the ballots for this standard are posted for stakeholder review.

Please use this electronic comment form to submit comments on MOD-004 standard by June 23, 2008.

If you need an off-line, unofficial copy of the questions in the comment form, there is a copy of the comment form posted at the following site:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

Please use only the electronic form to submit comments by June 23, 2008. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

### Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Maureen Long,*
*Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.*

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# Implementation Plan for Standard MOD-004 — Capacity Benefit Margin (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-004 — Capacity Benefit Margin, which describes the reliability aspects of determining and maintaining a Capacity Benefit Margin and the conditions under which that margin may be used.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes MOD-004. The following standards have been incorporated into this standard, made irrelevant by this standard, or are being addressed by the North American Energy Standards Board, and should be retired.

- MOD-005 — Procedure for Verifying CBM Values
- MOD-006 — Procedures for the Use of Capacity Benefit Margin Values
- MOD-007 — Documentation of the Use of Capacity Benefit Margin

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

- Transmission Service Provider
- Load Serving Entity
- Resource Planner
- Transmission Planner
- Balancing Authority

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Implementation Plan for Standard MOD-004 – Capacity Benefit Margin (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-004 – Capacity Benefit Margin, which describes the reliability aspects of determining and maintaining a Capacity Benefit Margin and the conditions under which that margin may be used.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes MOD-004. The following standards ~~MOD-005, MOD-006, and MOD-007~~ have been incorporated into this standard, made irrelevant by this standard, or are being addressed by the North American Energy Standards Board, and should be retired.

- MOD-005 — Procedure for Verifying CBM Values
- MOD-006 — Procedures for the Use of Capacity Benefit Margin Values
- MOD-007 — Documentation of the Use of Capacity Benefit Margin

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

- Transmission Service Provider
- Load Serving Entity
- Resource Planner
- Transmission Planner
- Balancing Authority

| ~~Proposed Standard~~ | ~~Transmission Operator~~ | ~~Transmission Planner~~ | ~~Transmission Service Provider~~ | ~~Balancing Authorities~~ | ~~Purchasing Selling Entities~~ | ~~Load-Serving Entities~~ |
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| ~~MOD-004~~ | | ~~■~~ | ~~■~~ | ~~■~~ | | ~~■~~ |

## Proposed Effective Date

**Implementation Plan for ~~Standards MOD-001,~~ MOD-004~~, MOD-008, MOD-028, MOD-029, and MOD-030; ATC/TTC/AFC and CBM/TRM Revisions~~ - Capacity Benefit Margin (Project 2006-07)**

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

Please use this form to submit comments on the current draft of MOD-004. Comments must be submitted by June 23, 2008. If you have questions please contact Andy Rodriquez at Andy.Rodriquez@nerc.net or by telephone at 202.393.3998.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007, FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

The drafting team has created the following proposed standard:

**MOD-004 — Capacity Benefit Margin.** A standard that describes the calculation and use of CBM.

The drafting team has also created five other standards (MOD-001, MOD-008, MOD-028, MOD-029, and MOD-030), for which comments are being sought through a different commenting period.

The drafting team also proposes the retirement of the following standards:

> **MOD-005 — Procedure for Verifying CBM Values.** Now addressed in compliance for MOD-004.
>
> **MOD-006 — Procedure for the Use of CBM.** Now addressed in MOD-004 R10, R11, and R12. Also to be addressed in future NAESB Business Practices.
>
> **MOD-007 — Documentation of the Use of CBM.** To be addressed in future NAESB Business Practices.

This standard was balloted March 3 to March 12, 2008. Many entities submitted negative ballots, and many submitted comments with their ballots. The drafting team has reviewed the comments submitted with ballots, and has made some changes to the standard to address these comments.

1. Based on industry comments, as well as those of the Functional Model Working Group, the Planned Resource Sharing Group (PRSG) has been eliminated. To address regional CBM processes, the Resource Planner was added as an applicable entity. Entities still may elect to register as a Joint Registration Organization (JRO), as well as delegate tasks.

2. The drafting team has modified the standard to be less prescriptive and allow for more flexibility in how the need for CBM and CBM itself is determined.

3. The requirement to waive timing and ramping requirements was modified to have a VRF of medium, as it has a direct impact on current-day operations and can result in the inadvertent denial of an interchange transaction needed to maintain reliability.

4. The requirement for a Transmission Service Provider to approve transactions using CBM if the CBM is available was modified to apply additional criteria to the evaluation for approval.

5. A more graded approach was applied to the VSLs where appropriate

The drafting team is now seeking comments on these changes.

You do not have to answer all questions.

1. The drafting team has modified the Violation Risk Factor for R11 and R12 of MOD-004 from Lower to Medium. NERC's VRF definitions are listed below:

   **High Risk Requirement:**

   (a) is a requirement that, if violated, could directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures; or
   (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk-Power System instability, separation, or a cascading sequence of failures, or could place the Bulk-Power System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

   **Medium Risk Requirement:**

   (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System, but is unlikely to lead to Bulk-Power System instability, separation, or cascading failures; or
   (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk-Power System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

   **Lower Risk Requirement: is administrative in nature and**

   (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor and control the Bulk-Power System; or
   (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk-Power System, or the ability to effectively monitor, control, or restore the Bulk-Power System.

   Are the current VRFs established correctly?

   ☐ Yes
   ☐ No
   ☐ No preference

   If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification. Comments:

2. The drafting team modified the applicable entities for the standard. Do you believe the applicable entities are correct?

☐ Yes

☐ No

☐ No preference

If "No," please identify entities should be applicable and what their roles should be. Comments:

3. The Drafting Team eliminated the detail regarding the request and response process for CBM. Do you believe this reduction in detail is appropriate?

   ☐ Yes

   ☐ No

   ☐ No preference

   If "No," please explain. Comments:

4. The drafting team has modified the Violation Severity Levels for MOD-004 to reflect industry concerns that they were too "pass/fail" oriented. Are the current VSLs established correctly?

   ☐ Yes

   ☐ No

   ☐ No preference

   If "No," please identify specific VSLs and suggest changes to the language. Comments:

5. The drafting team has modified the measures and compliance elements for MOD-004 based on industry comments. Do you believe these changes to the measures and compliance elements are appropriate?

   ☐ Yes

   ☐ No

   ☐ No preference

   If "No," please identify your concerns. Comments:

6. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-004. Comments:

| | Individual or group. | Name | Organization | Group Name | Lead Contact | Contact Organization | Question 1 | Question 1 Comments | Question 2 | Question 2 Comments | Question 3 | Question 3 Comments | Question 4 | Question 4 Comments | Question 5 | Question 5 Comments | Question 6 Comments |
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| | Group | | | NPCC | Guy Zito | NPCC | Yes | | Yes | | Yes | | Yes | | Yes | | |
| | Individual | Jack Cashin/Barry Green | EPSA | | | | No preference | | No preference | | No | . Some of the detail that has been eliminated was valuable and what is left resembles a fill-in-the-blank standard in some important aspects. For example, the previous draft required that CBM requirements be updated every 30 days. While the requirement for updates every 30 days may be excessive, it is important that the quantity withheld for CBM be reviewed regularly, as this transmission capability is not available for use by the market. We suggest a minimum of quarterly be required. The previous draft also specified the requirement for a TSP to make all CBM available to eligible parties requesting it (when in an EEA 2) even if some of those parties had needs that | No preference | | No preference | | In the following areas, EPSA believes that additional specificity in the standard would be beneficial. • The update frequency for specifying the quantities of CBM to be withheld (see question 3 above) • R3.1 specifies certain types of studies that are appropriate for the determination of CBM to be requested, for example LOLP studies. However, no guidance is provided on the appropriate target reliability. For example is 1 day in 10 years appropriate or 1 day in 100 years. • R3.2 requires the purchaser of CBM to specify the import paths or source region for the CBM. Is there any ability for the TSP to alter this request? If so, on what basis? On what frequency should |

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| | | | | | | | | | | | | exceeded amounts requested in advance. While EPSA agreed that this was appropriate at the time of the emergency, there needed to be a reconciliation after the fact, and a possible finding of a violation, if the appropriate amounts of CBM were not being requested and paid for and therefore inappropriate amounts of transmission capability were being withheld from the market. In the current draft standard, it is not clear that any requirement would be violated under these circumstances. | | | | | this information be updated? • In R12 there is no indication of a priority level when CBM is requested by multiple LSEs in an EEA 2 and less than the full requested amount is available. Is the CBM granted to the LSE that had requested that it be set aside (R3)? Is it merely first come first served? Under this scenario, where a single contingency prompts a request for CBM from multiple LSEs, this suggests that it would be granted to the LSE that completes the paper work most quickly. |
| | Individual | Greg Rowland | Duke Energy Corporation | | | | Yes | | Yes | | Yes | | Yes | | No | Section 1.3 Data Retention, first bullet should identify a maximum retention period, such as the most recent three calendar years plus the current year. | In Requirements R7 and R8, and Measures M7 and M8 the phrase "to meet their need" should be struck. This phrase implies that the CBM set-aside would be assigned/allocated to specific LSEs and Resource Planners, which is not the case. |
| | Individual | Dennis Kimm | MidAmerican Energy | | | | Yes | | No preference | | No | The standard is a fill-in-blank standard, and although probably won't be approved by the industry unless it is a fill-in-the blank standard, I will be in the minority and not vote for | No preference | | No preference | | NERC needs to develop clear standards for how the CBM value shall be determined, allocated across transmission paths, and used. The current standard does not require that to happen. |

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| | | | | | | | | | | | | this standard. | | | | | |
| | Individual | Danny Dees | MEAG Power | | | | No preference | | No preference | | No preference | | No preference | | No preference | | I wish to thank the SDT for its consideration of comments I submitted previously. Others at MEAG Power may choose to comment on other aspects of this standard; however, I comment solely to request that the SDT reconsider the wording of R12.3 in light of the fact that no Balancing Authority IS LOCATED WITHIN MEAG Power's service area. More specifically, MEAG Power's transmission system provides network service from network resources in Georgia to the loads of 48 cities and one county in Georgia. MEAG Power owns no transmission facilities outside of Georgia even though its system operates within the (multi-state) Southern Company Balancing Authority pursuant to a FERC-approved contract. Thus, MEAG Power is incapable of providing CBM to substantial amounts of load located within our host balancing authority (e.g., load located in Mississippi, Alabama and Florida). While it may not be typical for a TSP's service area to be a subset of its host balancing authority's footprint, I believe there are some others in this situation. Therefore, please consider if the |

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| | | | | | | | | | | | | | | | | | following alternative wording would be suitable: R12.3 The energy deficient entity in the Balancing Authority with the EEA 2 has load located within the Transmission Service Provider's area. |
| | Individual | Chuck Falls | SRP | | | | Yes | | Yes | | Yes | | No | VSL for R2 - The VSL ties the number of days for notification to others using the phrase "after a change was made" in the CBMID. The requirement R2 refers instead to "the effective date of the change" which may be different from the date a change is made in the CBMID. We suggest the wording at all levels of VSL for this requirement be modified to refer to the effective date of the change. VSL for R5 - None of the VSL levels are identified if the TSP never re-establishes the CBM once first established. Suggest adding the following words to the Severe VSL description " OR The TSP never re-establishes the CBM after first established." Also, in both the Moderate & Severe VSL description the words "if available" | Yes | | No other comments to offer. |

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| | | | | | | | | | | | | | | should be added following reference to R5.1 since none of the items in this section may be available which is acceptable per the first sentence in R5.1. VSL for R6 - Same comments apply as for R5 VSL. VSL for R7 - Change the "all" to "of" in the last sentence of the severe VSL. | | | |
| | | | | | | | | | | | | | | | | | R6: Can the SDT clarify the intent of "planning purposes during the subsequent years two through ten." Does this refer to transmission expansion planning or long term TSR planning? The Midwest ISO believes the intent is for transmission expansion planning. If this is true, then we believe that establishing/using a predetermined CBM value per path or flowgate should not be the only way to account for LOLE in the planning process. The Midwest ISO, through Module E of its Tariff, conducts Resource Adequacy studies to determine the total amount of generation available in its footprint and then derive the total amount of power remaining to satisfy its LOLE requirements. This remaining power can be accounted for by |

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| | Individual | John Harmon | Midwest ISO | | | | Yes | | Yes | | Yes | | Yes | | Yes | | building additional transmission in order to import or new generation can be built to meet the remaining power requirement. The Midwest ISO calculates CBM values for flowgates based on the remaining power requirement for short term (less than a year) ATC calculations. The Midwest ISO processes for Resource Adequacy and CBM Methodology have been through a Stakeholder process. We ask the SDT to consider the following language change: R6: The Transmission Planner shall establish a predetermined CBM value for each ATC Path or Flowgate or GCIR for each designated area to be used for future transmission planning during the subsequent years two through ten. R6.1 CBM and GCIR values shall reflect consideration of each of the following if available: •Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Planner's area •Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner's area •Any reserve margin or resource |

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| | | | | | | | | | | | | | | | | | adequacy requirements for loads within the Transmission Planner's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operations, Regional Reliability Organizations, or regional entities R6.2 Predetermined CBM values shall be allocated as follows: •For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners •For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner R6.3 Entities that do not utilize a predetermined CBM value in their respective planning process shall describe in their CBMID how the GCIR is calculated for each area and how the GCIR is used to calculate CBM values for ATC paths or Flowgates for selling transmission service. R8: The Midwest ISO believes this requirement will also need modification |

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| | | | | | | | | | | | | | | | | | based on our comments and proposed revision to R6. Please consider the language below: R8. Less than 31 calendar days after the establishment of CBM or GCIR, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the system being planned by the Transmission Planner of the amount of CBM set aside or the GCIR required to meet their resource adequacy requirements. |
| | | | | | | | | | | | | | | | | | 1. We question how the TSP can "elect" to maintain CBM per R1. What if, per R3, the LSE determined they had a need to set aside transmission capacity as CBM but their TSP does not maintain CBM? Per FERC Orders 890 and 693, the LSE has the right to request CBM be set aside if it can prove that it is a critical need based on LOLE, deterministic studies, historical data, etc. as described in R3. We suggest revising the first part of the first sentence of R1 to state "The Transmission Service Provider that has been asked by its LSE or RP to maintain CBM...". 2. Per R3 and R4, it is not clear how GCIR is used in the CBM process. Is it merely equal to |

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| | Group | | | FirstEnergy | Sam Ciccone | FirstEnergy Corp. | Yes | | No | Per our comments from Item 1 in Question 6 regarding the TSP electing to maintain CBM, we suggest changing "Transmission Planner, when their associated Transmission Service Provider has elected to maintain CBM" to simply "Transmission Planners". | Yes | We agree that the standard should be much less prescriptive as to how CBM is determined and utilized. | | | No | M6 - The phrase "(Note that CBM values may legitimately be zero)" should be removed from the measures and be integrated into the requirements. M10 - The end of the statement in the measure should say "EEA 2 or higher". | the CBM value or is it somehow used by the TSP to determine how much CBM is needed for each ATC Path or Flowgate? Either way, the standard should explain what is done with the GCIR once it has been established. 3. In R3.1 and R4.1, can the LSE and RP use different studies for different ATC Paths or Flowgates? If so, then R3.1 and R4.1 should be revised to state "Using one of the following for each ATC Path or Flowgate to determine the GCIR:". 4. With regard to R3 and the responsibilities of the LSE, currently many LSEs work with their TSP to determine the need for CBM because most LSEs do not have the capability to undertake these studies on their own. In addition, several LSEs participate within a Planned Resource Sharing Group that works with that sharing group's TSP to determine the need for CBM. We assume that these activities would be permitted to continue and that this standard will not preclude LSEs from working with their TSP to determine CBM needs. We ask the SDT to confirm our assumptions. |
| | | | | | | | | At present, ERCOT does not use the concept of CBM in its operating activities. Therefore, I | | I believe language should be added to make it very clear that only those | | | | At present, ERCOT does not use the concept of CBM in its operating activities. | | At present, ERCOT does not use the concept of CBM in its operating activities. Therefore, I | |

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| | Individual | H. Steven Myers | ERCOT | | | | No preference | do not feel it would be appropriate for me to comment upon the VRFs. I believe that ATC, TTC, AFC, CBM, and TRM are concepts that apply to the operation of a Transmission Service Market and do not have an associated reliability function if such a market is not in use. | No | entities that have ATC paths are applicable. I believe that the Requirements have been modified to indicate that only such entities that use the concept of CBM have a performance expected, but further clarifying the applicable entities language would help to make it even clearer. | Yes | | No preference | Therefore, I do not feel it would be appropriate for me to comment upon the VSLs. I believe that ATC, TTC, AFC, CBM, and TRM are concepts that apply to the operation of a Transmission Service Market and do not have an associated reliability function if such a market is not in use. | No preference | do not feel it would be appropriate for me to comment upon the measures and compliance elements. I believe that ATC, TTC, AFC, CBM, and TRM are concepts that apply to the operation of a Transmission Service Market and do not have an associated reliability function if such a market is not in use. | |
| | | | | | | | | | | The Applicability section of the | | | | VSL for R2: The VSL should be based on whether the TSP gave prior notice to changes in the CBMID before the changes took effect. Hence the requirement needs to be modified to specify how much "prior" is acceptable. We propose 30 days as appropriate. Hence the VSLs could be: Low = "... notification of less than 30 days but greater than 20 days of effective date." Medium = "... notification of 20 days or less but greater than 10 days of effective..." High = "... notification of 10 days or less but greater than 1 day of effective | | | Effective Date: We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in standards that |

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| | Individual | Alessia Dawes | Hydro One Networks | | | | Yes | | No | standard reads as if maintaining a CBM is optional. We have concern with the following: Section 4.5 "Transmission Planners, when their associated Transmission Service Provider has elected to maintain CBM." This reads as though the TSP has the option of not maintaining a CBM and hence a TP has no responsibility as well. We suggest removing the "... when their associated TSP has elected to maintain CBM..." as it is manditory that CBM is established and maintained (even if it is zero). | Yes | | No | date..." Severe = "... gave 1 day or no notice of change prior to the effective date ..." As well, the VSLs for the second condition of R2 (the entities requiring CBMID) use the word "some" which is a loose term. We suggest rewording the "AND" part of the VSLs as follows: High = " ...made available the CBMID to less than 100% but greater than 50% of all entities listed in R2 who require it." Severe = "...made available the CBMIS to 50% or less of all entities listed in R2 who require it." VSLs for R7, R8 and R9 using this "some" loosely as well. We recommend the same wording recommended for R2 VSLs above. VSL for R6: The VSL ranges need to be modified to match the requirement range OR change the requirement to state the frequency at which they must maintain the subsequent 2 to 10 year CBM values. Also, requirement R6 induces | Yes | | have a clear reliability impact. In addition, it does not seem appropriate to have entities exposed to sanctions for non-compliance in some jurisdictions while not in others. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan posted documents permit that these Standards are effective in some jurisdictions and not others. The Standard and the Implementation Plan should be modified to ensure that they become effective in all jurisdictions at the same time, including those where such regulatory approval in not required, that is, only when all regulatory approvals have been obtained. We suggest the same words used in MOD-001, 28, 29 and 30 be used: “All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by all applicable regulatory authorities.” R11 and R12: We think these requirements belong in the INT standards which deals with reliability assessment of Arranged Interchange. |

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| | | | | | | | | | | | | | | the question "subsequent to what?" Do we assume subsequent to R5's 13 months? We may be interpreting the requirement wrong. If so, please rephrase the requirement. | | | |
| | Individual | Catherine Wesley | PJM | | | | Yes | | Yes | | Yes | | Yes | | Yes | | PJM submits the following comments for consideration. PJM proposes revising Requirement 6 as follows: R6 - At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used during the subsequent years 2 through 10. This value shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] PJM proposes the addition of a new Requirement 7 as follows: New R7 - At least every 13 months, the Transmission Planner shall establish a CBM value to be used for planning purposes during the subsequent years 2 through 10. This value shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] PJM agrees that Requirements 10, 11 and 12 are essential. PJM identifies these requirements as addressing emergency scenarios. PJM proposes that it is more appropriate to include these requirements in |

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| | | | | | | | | | | | | | | | | | EOP-002, Attachment 1 which governs emergency operations. |
| | Group | | | ISO RTO Council/Standards Review Committee | Charles Yeung | Southwest Power Pool | Yes | | Yes | | Yes | | No | We agree with all VSLs except the following: R2: The structure of R2 is fine, but the identification of "late" notification of changes to CBMID needs to be based upon some specific time frame requirement in R2, which is absent in this draft standard. Please see our related comments under Q6. Further, the second condition for the HIGH VSL is loose. It assigns a HIGH to the TSP if it made available the CBMID to "some", but not all, of the entities specified in R2. "Some" needs to be more specific as otherwise, it will be a basis for argument in an audit process. Suggest to expand and grade the second condition VSLs by 1, 2, 3 and 4 or more for Low, Medium, High and Severe. R7: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. R8: Same | Yes | | R2: It requires the TSP to notify those entities of any changes to the CBMID prior to the effective date of the change. There should be a time frame specified for the notification to tighten up the requirement and facilitate proper development of measures and VSLs. Given that the changes affect the CBMID, we'd think that a period of 7 to 30 days would be approriate. R9: It requires the TSP and TP to provide copies of the supporting data, including any models, used for determining CBM to a number of entities. It should be noted that some of these requesting entities may have commercial interests or affiliations. Further, in some established markets or jurisdictions, the TSPs and/or the TPs may not be able to provide such data, especially the model, to a third party. We suggest this requirement be qualified by adding "subject to confidentiality and security requirements" as in MOD-001, R8. R11 and R12: We think these 2 requirements |

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| | | | | | | | | | | | | | | comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. R9: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. In this case, the graded VSLs can be based on the percentage of total data requested. | | | should be moved to INT-006 which deals with reliability assessment of Arranged Interchange. The draft INT-006 being posted for comments deals specifically with emergency requests (and reliability adjustment requests). |
| | Individual | Ron Falsetti | Ontario IESO | | | | Yes | | Yes | | Yes | | No | We agree with all VSLs except the following: R2: The structure of R2 is fine, but the identification of "late" notification of changes to CBMID needs to be based upon some specific time frame requirement in R2, which is absent in this draft standard. Please see our related comments under Q6. Further, the second condition for the HIGH VSL is loose. It assigns a HIGH to the TSP if it made available the CBMID to "some", but not all, of the entities specified in R2. "Some" needs to be more specific as otherwise, it will be a basis for argument in an audit process. Suggest to | Yes | | R2: It requires the TSP to notify those entities of any changes to the CBMID prior to the effective date of the change. There should be a time frame specified for the notification to tighten up the requirement and facilitate proper development of measures and VSLs. Given that the changes affect the CBMID, we'd think that a period of 7 to 30 days would be approriate. R9: It requires the TSP and TP to provide copies of the supporting data, including any models, used for determining CBM to a number of entities. It should be noted that some of these requesting entities may have commercial interests or affiliations. Further, in some established |

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| | | | | | | | | | | | | | | expand and grade the second condition VSLs by 1, 2, 3 and 4 or more for Low, Medium, High and Severe. R7: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. R8: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. R9: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. In this case, the graded VSLs can be based on the percentage of total data requested. | | | markets or jurisdictions, the TSPs and/or the TPs may not be able to provide such data, especially the model, to a third party. We suggest this requirement be qualified by adding "subject to confidentiality and security requirements" as in MOD-001, R8. R11 and R12: We think these 2 requirements should be moved to INT-006 which deals with reliability assessment of Arranged Interchange. The draft INT-006 being posted for comments deals specifically with emergency requests (and reliability adjustment requests). |
| | | | | | | | | ATC supports the change to raise R11 and R12 from lower to medium. This is an example where clearly there is the potential for | | | | | | | | | 1. Due to the Midwest ISO methodology of calculating CBM in the short-term (1 year) and GCIR in the long-term, we believe that R6 should be changed to include: "GCIR for each designated area to be used for future transmission planning." and add the words "that maintains CBM" after "the Transmission Planner" 2. R6.1 should include "CBM and GCIR values shall reflect consideration of each of the following if available". 3. R6.3 should include |

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| | Individual | Jason Shaver | American Transmission Company | | | | No | violations to "directly affect the electrical state or the capability of the Bulk-Power System" as described in the definition for the Medium Risk Requirement. In addition, ATC suggests that R10 be assigned as a "Medium" VRF as well. There is the potential for violations to "directly affect the electrical state or the capability of the Bulk-Power System" as described in the definition for the Medium Risk Requirement. | No preference | | Yes | ATC supports the proposed elimination of excess detail. In addition, ATC suggests that R9 be changed to "The Transmission Service Provider or Transmission Planner that maintains CBM shall provide copies of the applicable supporting data". | Yes | | Yes | | "Entities that do not utilize a predetermined CBM value in their respective planning process shall describe in their CBMID how the GCIR is calculated for each area and how the GCIR is used to calculate CBM values for ATC paths or Flowgates for selling transmission service." 4. R8 should include "Less than 31 calendar days after the establishment of CBM or GCIR, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for GCIR on the system being planned by the Transmission Planner of the amount of CBM set aside or the GCIR required to meet their need." 5. Change the wording in 1.3 Data Retention to: "The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted audit records." |
| | | | | | | | | | | | | | | | | | How would a generator in a neighboring Balancing Authority (or control area) provide the CBM due to a sudden generation outage in the host control area (or BA area) where the outage occurred? The CBM would be provided after the TRM and has been established as a reliability |

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| | Group | | | Bonneville Power Administration | Denise Koehn | Transmission Reliability Program | No preference | | No preference | | No | Why isn't the LSE among the entities listed in sec B.R.2, to which the TSP must make the current copy of the CBMID available to? | No preference | | No preference | | requirement by an LSE. The ATC DT should explain how this standard ensures that an LSE can replace the lost generation from a neighboring BA. New Section A.5. Effective date : On the third line, "become" should be "becomes" that is unless they intend to pluralize standard to be standards. CBM is a scheduled transmission reservation that is implemented following the expiration of the TRM. (TRM is unscheduled transmission capacity that can be used to implement emergency operations up to 59 minutes.) Would like to suggest that that the scope of Project 2009-09, a Resource Adequacy Assessments Standard, which is slated for development in 2009, be enlarged to include aspects of MOD-004 that relate to defining the four analyses upon which the GCIR determination is based in greater detail. Although we agree that any one of these analyses is appropriate in calculating GCIR, we believe that these analyses need to be defined in greater detail in order to achieve the stated purpose of the standard. The stated purpose of this standard is: "To promote the consistent and reliable calculation, verification, |

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| | | | | | | | | | | | | | | | | | | preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations." The standard also states that the determination of Generation Capability Import Requirement (GCIR), which is the basis for the CBM request, can be calculated using any of the following analyses: (1) Loss of Load Expectation (LOLE) studies, (2) Loss of Load Probability (LOLP) studies, (3) Deterministic risk-analysis studies and (4) Reserve margin or resource adequacy requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability. |

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

## Consideration of Comments on Draft Standard — MOD-001-4 — Project 2006-07

The ATC Standards Drafting Team thanks all commenters who submitted comments on the draft standard MOD-004-1. These standards were posted for a 30-day public comment period from May 23, 2008 through June 23, 2008. The stakeholders were asked to provide feedback on the standard through a special electronic Standard Comment Form. There were 15 sets of comments, including comments from 51 different people from approximately 30 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

There were many comments that led that drafting team to correct typographical errors, and to modify language to improve clarity, but none of the changes made by the drafting team changed the scope or intent of the requirements in the standard.

**Requirements**

- One entity suggested adding the Load Serving Entity to the list of entities to which the CBMID must be made available to in R2. The SDT incorporated the proposed language, and also added the Balancing Authority.
- One entity that supported the reduction in detail suggested that R9 be modified to require the provision of "applicable" supporting data. The SDT incorporated the proposed language.
- One entity suggested that the NERC standards were requiring CBM to be treated on a first-come, first served basis, As CBM is a margin, the SDT believes that the first entity that needs CBM should be allowed to use it. If a conflict arises due to competing needs, the SDT believes it is up to tariffs and/or business practices to determine the appropriate way to manage the conflict. The SDT has expanded R1.3 to require an explanation of how competing requests for use of CBM are handled.
- One entity requested that the phrase "to meet their need" be removed from R7, R8, M7 and M8, as that implied assignment of CBM like a reservation. The SDT removed the language.
- One entity identified a problem where TSP boundaries and BA boundaries were not consistent. The SDT modified the standard to address the commenter's concern by modifying R12.3 to read as follows: "The Load of the Energy Deficient Entity is located within the Transmission Service Provider's area."
- One entity pointed out that the standard indicated that only one study could be used to determine GCIR. The SDT modified the standard to allow use of multiple methods.
- One entity suggested that R9 include a provision that restricts data "subject to confidentiality and security requirements." The SDT incorporated the suggested language.

**Compliance**

- Several entities provided detailed comments with regard to Requirement 6. After careful review, the SDT determined that the providers' underlying concerns could be addressed with the current standard's language, provided that it was clear in the measure that the practices employed by those entities were acceptable. The SDT has modified measure M6 to address this concern by adding the following sentence: "Inclusion of GCIR based on R6.1 and R6.2 within the transmission base case meets this requirement."
- Four entities pointed out that the VSL for R2 referred generically to a "change" without specifying whether that change was in the CBMID or in the implementation. The SDT modified the standard to be clear that the VSL was based on the effective date of the change to the implementation. Some of those entities suggested changes to the timeframes for lateness, and recommended requiring a specific time ahead of a change for

notification. The SDT explained that that there are situations where rapid changes to the CBMID or its implementation could be required, and that limitations as suggested could delay entities from making those changes.

- One entity pointed out that the VSLs for R5 and R6 only referred to "re-establishment" of a value – but no initial establishment. The SDT corrected the oversight. The entity also pointed out that the VSLs for R5 and R6 did not allow for the requirement not to be met if information was not available; the SDT modified the language to be clear.
- Several entities felt the use of the phase "some, but not all" was ambiguous. The SDT modified the VSLs to refer instead to "at least one."
- One entity asked for limits to be placed on the data retention for R1; the SDT did so by adding the phrase "(but not more than the most recent three calendar years plus the current year)."
- One entity also pointed out that Measure 10 did not allow for the consideration of an EEA3; the SDT modified the language to allow for that consideration.

**Concepts**

- It was suggested that some of the requirements in the standard should be moved to either the EOP or INT families of standards. The SDT incorporated these requirements into this standard, as they are directly related to CBM. Additionally, the INT and EOP standards are outside the scope of this effort as defined by its SAR. Until such time as a SAR is submitted to move the requirements from this standard to another set of standards, the SDT believes it is more important to have the requirements approved and enforceable.

- It was suggested that Project 2009-09, a Resource Adequacy Assessments Standard, which is slated for development in 2009, be enlarged to include aspects of MOD-004 that relate to defining the four analyses upon which the GCIR determination is based in greater detail. SDT suggested that the commenter submit a suggestion for inclusion in the development of NERC's Work Plan. Suggestions may be submitted through the Reliability Standards Suggestions and Comment Form: http://www.nerc.com/files/Standards_Input_Form_Final_2008June30.doc

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving this standard forward to posting for pre-ballot consideration.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standard can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

## Index to Questions, Comments, and Responses

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Ralph Rufrano | New York Power Authority – NPCC Standards Review Committee | | | | | | | | | | x |

| Additional Member | Additional Organization | Region | Segment Selection | |
|---|---|---|---|---|
| 1. | Ralph Rufrano | New York Power Authority | NPCC | 5 |
| 2. | Michael Ranalli | National Grid | NPCC | 4 |
| 3. | Frederick White | Northeast Utilities | NPCC | 1 |
| 4. | William DeVries | New York Independent System Operator | NPCC | 2 |
| 5. | Brian Evans-Mongeon | Utility Services | NPCC | 6 |
| 6. | Ed Thompson | Consolidated Edison Co. of New York, Inc. | NPCC | 1 |
| 7. | Kathleen Goodman | ISO - New England | NPCC | 2 |
| 8. | Don Nelson | Massachusetts Dept. of Public Utilities | NPCC | 9 |
| 9. | Sylvain Clermont | Hydro-Quebec TransEnergie | NPCC | 1 |
| 10. | Michael Gildea | Constellation Energy | NPCC | 6 |
| 11. | Randy MacDonald | New Brunswick System Operator | NPCC | 2 |
| 12. | Al Adamson | New York State Reliability Council | NPCC | 9 |
| 13. | Lee Pedowicz | NPCC | NPCC | 10 |

| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2. | Jack Cashin/Barry Green | Electric Power Supply Association | | | | | x | x | | | | |
| 3. | Greg Rowland | Duke Energy Corporation | x | | x | | x | x | | | | |
| 4. | Dennis Kimm | MidAmerican Energy | | | | | | x | | | | |
| 5. | Danny Dees | MEAG Power | x | | x | | x | | | | | |
| 6. | Chuck Falls | Salt River Project | x | | x | | x | x | | | | |
| 7. | John Harmon | Midwest ISO, Inc. | | x | | | | | | | | |
| 8. | Doug Hohlbaugh | FirstEnergy Corp. | x | | | | | | | | | |

| Additional Member | Additional Organization | Region | Segment Selection | |
|---|---|---|---|---|
| 1. | Doug Hohlbaugh | FE | RFC | 1, 3, 5, 6 |
| 2. | Dave Folk | FE | RFC | 1, 3, 5, 6 |
| 3. | Larry Hartley | FE | RFC | 3 |
| 4. | Ron Andras | FE | RFC | 3 |
| 5. | Dan Huffman | FE | RFC | 3 |
| 6. | Gavin Cunningham | FE | RFC | 3 |

| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9. | H. Steven Myers | ERCOT | | x | | | | | | | | |
| 10. | Alessia Dawes | Hydro One Networks | | | | | | | | | | |
| 11. | Catherine Wesley | PJM Interconnection, L.L.C. | | x | | | | | | | | |

| | Commenter | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 12. | Charles Yeung | Southwest Power Pool – ISO/RTO Council | | x | | | | | | | | |

| Additional Member | Additional Organization | Region | Segment Selection | |
|---|---|---|---|---|
| 1. | Patrick Brown | PJM | RFC | 2 |
| 2. | Jim Castle | NYISO | NPCC | 2 |
| 3. | Ron Falsetti | IESO | NPCC | 2 |
| 4. | Matt Goldberg | ISO NE | NPCC | 2 |
| 5. | Brent Kingsford | CAISO | WECC | 2 |
| 6. | Anita Lee | AESO | WECC | 2 |
| 7. | Steve Myers | ERCOT | ERCOT | 2 |
| 8. | Bill Phillips | MISO | RFC | 2 |

| | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13. | Ron Falsetti | Ontario IESO | | x | | | | | | | | |
| 14. | Jason Shaver | American Transmission Company | x | | | | | | | | | |
| 15. | Denise Koehn | Bonneville Power Administration | x | | x | | x | x | | | | |

| Additional Member | Additional Organization | Region | Segment Selection | |
|---|---|---|---|---|
| 1. | Abbey Nulph | Transmisson | WECC | 1, 3, 5, 6 |
| 2. | Rebecca Berdhal | Power | WECC | 1, 3, 5, 6 |
| 3. | Frances Halpin | Power | WECC | 1, 3, 5, 6 |
| 4. | Mary Johannis | Power | WECC | 1, 3, 5, 6 |
| 5. | Eric King | Power | WECC | 1, 3, 5, 6 |
| 6. | Don Wolfe | Power | WECC | 1, 3, 5, 6 |
| 7. | Patrick Rochelle | Transmission | WECC | 1, 3, 5, 6 |
| 8. | Susan Millar | Transmission | WECC | 1, 3, 5, 6 |

1. The drafting team has modified the Violation Risk Factor for R11 and R12 of MOD-004 from Lower to Medium. Are the current VRFs established correctly? If "No," please identify which VRFs are incorrect, how they should be modified, and a justification for their modification.

**Summary Consideration:** Most entities supported this change.

One entity suggested raising the VRF for R10 as well. The SDT believes that a Lower VRF for R10 is correct. R10 requires that an entity use CBM only if in an EEA2. If not in an EEA2 and the CBM is requested to be used, there should be a minimal adverse impact to reliability. The SDT would expect that if such a request were made it would be denied; if it were inadvertently approved, it would subsequently be curtailed.

| Individual/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| ERCOT | No preference | At present, ERCOT does not use the concept of CBM in its operating activities. Therefore, I do not feel it would be appropriate for me to comment upon the VRFs. I believe that ATC, TTC, AFC, CBM, and TRM are concepts that apply to the operation of a Transmission Service Market and do not have an associated reliability function if such a market is not in use. |
| Response: If ERCOT does not use the concept of CBM, this standard would not apply to ERCOT. | | |
| American Transmission Company | No | ATC supports the change to raise R11 and R12 from lower to medium. This is an example where clearly there is the potential for violations to "directly affect the electrical state or the capability of the Bulk-Power System" as described in the definition for the Medium Risk Requirement. In addition, ATC suggests that R10 be assigned as a "Medium" VRF as well. There is the potential for violations to "directly affect the electrical state or the capability of the Bulk-Power System" as described in the definition for the Medium Risk Requirement. |
| Response: The SDT believes that a Low VRF for R10 is correct. R10 requires that an entity use CBM only if in an EEA2. If not in an EEA2 and the CBM is requested to be used, there should be a minimal adverse impact to reliability. The SDT would expect that if such a request was made it would be denied; if it was inadvertently approved, it would subsequently be curtailed. | | |
| NPCC SRC | Yes | |
| Duke Energy Corporation | Yes | |
| MidAmerican Energy | Yes | |
| Salt River Project | Yes | |
| Midwest ISO, Inc. | Yes | |
| FirstEnergy Corp. | Yes | |
| Hydro One Networks | Yes | |
| PJM | Yes | |

| Individual/Group | Question 1: | Question 1 Comments: |
|---|---|---|
| Interconnection, L.L.C. | | |
| ISO/RTO Council | Yes | |
| Ontario IESO | Yes | |
| Electric Power Supply Association | No preference | |
| MEAG Power | No preference | |
| Bonneville Power Administration | No preference | |

2. The drafting team modified the applicable entities for the standard. Do you believe the applicable entities are correct? If "No," please identify entities should be applicable and what their roles should be.

**Summary Consideration:** Most entities agreed the applicable entities were correct.

Two entities suggested that the exclusion for Transmission Planners whose Transmission Service Provider did not maintain CBM was incorrect, and that all Transmission Service Providers (and therefore all Transmission Planners) had to follow the standard. Paragraph 82 of FERC Order 890-A states "The Commission clarifies in response to Duke that utilities do not need to make CBM available to LSEs on their system if the utilities do not reserve for themselves CBM or its equivalent." Accordingly, the SDT has written the requirements and applicability such that only entities who maintain a CBM are required to follow this standard. For Transmission Planners, this is addressed in the "Applicability" section of the standard; for Transmission Service Providers, however, some requirements apply to all Transmission Service Providers, while others apply only to those who maintain CBM – in this case, the applicability has been explicitly identified in the requirements themselves.

One entity suggested that this standard should not apply if an entity maintained CBM but did not use one of the three ATC methodologies. The SDT believes that the applicability is clear as written, and requires no modification.

| Individual/Group | Question 2: | Question 2 Comments: |
|---|---|---|
| FirstEnergy Corp. | No | Per our comments from Item 1 in Question 6 regarding the TSP electing to maintain CBM, we suggest changing "Transmission Planner, when their associated Transmission Service Provider has elected to maintain CBM" to simply "Transmission Planners". |
| Response: Paragraph 82 of FERC Order 890-A states "The Commission clarifies in response to Duke that utilities do not need to make CBM available to LSEs on their system if the utilities do not reserve for themselves CBM or its equivalent." Accordingly, the SDT has written the requirements and applicability such that only entities who maintain a CBM are required to follow this standard. For Transmission Planners, this is addressed in the "Applicability" section of the standard; for Transmission Service Providers, however, some requirements apply to all Transmission Service Providers, while others apply only to those who maintain CBM – in this case, the applicability has been explicitly identified in the requirements themselves. | | |
| ERCOT | No | I believe language should be added to make it very clear that only those entities that have ATC paths are applicable. I believe that the Requirements have been modified to indicate that only such entities that use the concept of CBM have a performance expected, but further clarifying the applicable entities language would help to make it even clearer. |
| Response: The SDT believes that the applicability is clear as written, and requires no modification. | | |
| Hydro One Networks | No | The Applicability section of the standard reads as if maintaining a CBM is optional. We have concern with the following: Section 4.5 "Transmission Planners, when their associated Transmission Service Provider has |

| Individual/Group | Question 2: | Question 2 Comments: |
|---|---|---|
| | | elected to maintain CBM." This reads as though the TSP has the option of not maintaining a CBM and hence a TP has no responsibility as well. We suggest removing the "…when their associated TSP has elected to maintain CBM?" as it is mandatory that CBM is established and maintained (even if it is zero). |
| Response: Paragraph 82 of FERC Order 890-A states "The Commission clarifies in response to Duke that utilities do not need to make CBM available to LSEs on their system if the utilities do not reserve for themselves CBM or its equivalent." Accordingly, the SDT has written the requirements and applicability such that only entities who maintain a CBM are required to follow this standard. For Transmission Planners, this is addressed in the "Applicability" section of the standard; for Transmission Service Providers, however, some requirements apply to all Transmission Service Providers, while others apply only to those who maintain CBM – in this case, the applicability has been explicitly identified in the requirements themselves. | | |
| NPCC SRC | Yes | |
| Duke Energy Corporation | Yes | |
| Salt River Project | Yes | |
| Midwest ISO, Inc. | Yes | |
| PJM Interconnection, L.L.C. | Yes | |
| ISO/RTO Council | Yes | |
| Ontario IESO | Yes | |
| Electric Power Supply Association | No preference | |
| MidAmerican Energy | No preference | |
| MEAG Power | No preference | |
| American Transmission Company | No preference | |
| Bonneville Power Administration | No preference | |

3. The Drafting Team eliminated the detail regarding the request and response process for CBM. Do you believe this reduction in detail is appropriate? If "No," please explain.

**Summary Consideration:** In general, entities were supportive of the reduction in detail. Three entities expressed concern with the reduction in detail.

One of those entities expressed concern that the standard was a "fill in the blank" standard. The SDT has attempted to draft the standard such that it is compatible with many other previously approved implementations of CBM. The SDT believe that this version of the standard is significantly more detailed than the existing standard, and although less prescriptive than some may desire, is not "fill in the blank."

One of those entities suggested that more frequent reviews of CBM should be undertaken, and that the standard should explain how to deal with equity and financial issues related to scarcity of CBM in real-time. Regarding the more frequent reviews, the SDT has identified through previous drafts and comment that the industry believes a less frequent review is appropriate. The SDT notes that only one entity expressed this concern. Regarding the question of equity and financial issues, the SDT does not believe that reconciliation of CBM and financial compensation is within the scope of this standards effort, and more properly belongs within tariffs, business practices, or other documents related to equity issues.

The last of those entities suggested that the Load Serving Entity be included in the list of entities to which the CBMID must be made available to. The SDT incorporated the proposed language, and also added the Balancing Authority.

One entity that supported the reduction in detail suggested that R9 be modified to require the provision of "applicable" supporting data. The SDT incorporated the proposed language.

| Individual/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| Electric Power Supply Association | No | Some of the detail that has been eliminated was valuable and what is left resembles a fill-in-the-blank standard in some important aspects. For example, the previous draft required that CBM requirements be updated every 30 days. While the requirement for updates every 30 days may be excessive, it is important that the quantity withheld for CBM be reviewed regularly, as this transmission capability is not available for use by the market. We suggest a minimum of quarterly be required.<br><br>Response: Through previous drafts and comments, the SDT has identified that the industry believes a less frequent review is appropriate.<br><br>The previous draft also specified the requirement for a TSP to make all CBM available to eligible parties requesting it (when in an EEA 2) even if some of those parties had needs that exceeded amounts requested in |

| Individual/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| | | advance. While EPSA agreed that this was appropriate at the time of the emergency, there needed to be a reconciliation after the fact, and a possible finding of a violation, if the appropriate amounts of CBM were not being requested and paid for and therefore inappropriate amounts of transmission capability were being withheld from the market. In the current draft standard, it is not clear that any requirement would be violated under these circumstances.<br><br>Response: The SDT does not believe that reconciliation of CBM and financial compensation is within the scope of this standards effort, and more properly belongs within tariffs, business practices, or other documents related to equity issues. |
| Response: Please see in-line responses. | | |
| MidAmerican Energy | No | The standard is a fill-in-blank standard, and although probably won't be approved by the industry unless it is a fill-in-the blank standard, I will be in the minority and not vote for this standard. |
| Response: The SDT has attempted to draft the standard such that it is compatible with many other previously approved implementations of CBM. The SDT believe that this version of the standard is significantly more detailed than the existing standard. | | |
| Bonneville Power Administration | No | Why isn't the LSE among the entities listed in sec B.R.2, to which the TSP must make the current copy of the CBMID available to? |
| Response: The SDT has modified the standard to incorporate the suggested change, as well as include Balancing Authorities. The new language reads as follows: "R2. The Transmission Service Provider that maintains CBM shall make available its current CBMID to the Transmission Operators, Transmission Service Providers, Reliability Coordinators, Transmission Planners, Resource Planners, and Planning Coordinators that are within or adjacent to the Transmission Service Provider's area, and to the Load Serving Entities and Balancing Authorities within the Transmission Service Provider's area, and notify those entities of any changes to the CBMID prior to the effective date of the change." However, the SDT also notes that current draft NAESB business practices also require this information to be posted on the OASIS. | | |
| American Transmission Company | Yes | ATC supports the proposed elimination of excess detail. In addition, ATC suggests that R9 be changed to "The Transmission Service Provider or Transmission Planner that maintains CBM shall provide copies of the applicable supporting data". |
| Response: The SDT has made the requested change. The new language is, "R9. The Transmission Service Provider that maintains CBM and the Transmission Planner shall each provide (subject to confidentiality and security requirements) copies of the applicable supporting data, including any models, used for determining CBM or allocating CBM over each ATC Path or Flowgate to the following:" | | |
| FirstEnergy Corp. | Yes | We agree that the standard should be much less prescriptive as to how CBM is determined and utilized. |
| Response: Thank you for your supportive comment. | | |
| NPCC SRC | Yes | |
| Duke Energy Corporation | Yes | |
| Salt River Project | Yes | |
| Midwest ISO, Inc. | Yes | |

| Individual/Group | Question 3: | Question 3 Comments: |
|---|---|---|
| ERCOT | Yes | |
| Hydro One Networks | Yes | |
| PJM Interconnection, L.L.C. | Yes | |
| ISO/RTO Council | Yes | |
| Ontario IESO | Yes | |
| MEAG Power | No preference | |

4. The drafting team has modified the Violation Severity Levels for MOD-004 to reflect industry concerns that they were too “pass/fail” oriented. Are the current VSLs established correctly? If “No,” please identify specific VSLs and suggest changes to the language.

**Summary Consideration:** Four entities expressed concern with the VSLs.

Four entities pointed out that the VSL for R2 referred generically to a “change” without specifying whether that change was in the CBMID or in the implementation. The SDT modified the standard to be clear that the VSL was based on the effective date of the change to the implementation. Some of those entities suggested changes to the timeframes for lateness, and require a specific time ahead of a change for notification. The SDT explained that that there are situations where rapid changes to the CBMID or its implementation could be required, and that limitations as suggested could delay entities from making those changes.

One entity pointed out that the VSLs for R5 and R6 only referred to “re-establishment” of a value – but no initial establishment. The SDT corrected the oversight. The entity also pointed out that the VSLs for R5 and R6 did not allow for the requirement not to be met if information was not available; the SDT modified the language to be clear.

Several entities felt the use of the phase “some, but not all” was ambiguous. The SDT modified the VSLs to refer instead to “at least one.”

| Individual/Group | Question 4: | Question 4 Comments: |
|---|---|---|
| Salt River Project | No | VSL for R2 - The VSL ties the number of days for notification to others using the phrase "after a change was made" in the CBMID. The requirement R2 refers instead to "the effective date of the change" which may be different from the date a change is made in the CBMID. We suggest the wording at all levels of VSL for this requirement be modified to refer to the effective date of the change.<br><br>Response: The SDT has modified the VSL as suggested.<br><br>VSL for R5 - None of the VSL levels are identified if the TSP never re-establishes the CBM once first established. Suggest adding the following words to the Severe VSL description " OR The TSP never re-establishes the CBM after first established." Also, in both the Moderate & Severe VSL description the words "if available" should be added following reference to R5.1 since none of the items in this section may be available which is acceptable per the first sentence in R5.1.<br><br>Response: The SDT believe that the first issue is already addressed by requiring re-establishing the value after a previous establishment. However, the SDT has added a Severe VSL criteria for entities that maintain |

| Individual/Group | Question 4: | Question 4 Comments: |
|---|---|---|
| | | CBM but have not established an initial value. The SDT has modified the “Moderate” reference to R5.1 to address whether data was available; the “Severe” reference already included this language.<br><br>VSL for R6 - Same comments apply as for R5 VSL.<br>Response: The SDT believe that the first issue is already addressed by requiring re-establishing the value after a previous establishment. However, the SDT has added a Severe VSL criteria for entities that maintain CBM but have not established an initial value. The SDT has modified the “Moderate” reference to R6.1 to address whether data was available; the “Severe” reference already included this language.<br><br>VSL for R7 - Change the "all" to "of" in the last sentence of the severe VSL.<br>Response: The SDT has corrected this typographical error. |
| Response: Please see in-line responses. | | |
| Hydro One Networks | No | VSL for R2: The VSL should be based on whether the TSP gave prior notice to changes in the CBMID before the changes took effect. Hence the requirement needs to be modified to specify how much "prior" is acceptable. We propose 30 days as appropriate. Hence the VSLs could be:<br><br>Low = "…notification of less than 30 days but greater than 20 days of effective date."<br>Medium = "… notification of 20 days or less but greater than 10 days of effective…"<br>High = "…notification of 10 days or less but greater than 1 day of effective date…"<br>Severe = "… gave 1 day or no notice of change prior to the effective date …"<br><br>Response: The SDT believes that there are situations where rapid changes to the CBMID or its implementation could be required, and that limitations as suggested could delay entities from making those changes. Accordingly, the SDT did not elect to specify a minimum notice period for the requirement. Based on previous comments, the SDT has modified R2 to refer to the “effective date” rather than simply “the change.”<br><br>As well, the VSLs for the second condition of R2 (the entities requiring CBMID) use the word "some" which is a loose term. We suggest rewording the "AND" part of the VSLs as follows:<br><br>High = " …made available the CBMID to less than 100% but greater than 50% of all entities listed in R2 who require it."<br>Severe = "…made available the CBMIS to 50% or less of all entities listed in R2 who require it." |

| Individual/Group | Question 4: | Question 4 Comments: |
|---|---|---|
| | | VSLs for R7, R8 and R9 using this "some" loosely as well. We recommend the same wording recommended for R2 VSLs above.<br><br>Response: To be clearer, the SDT has replaced the word “some” with “at least one.”<br><br>VSL for R6: The VSL ranges need to be modified to match the requirement range OR change the requirement to state the frequency at which they must maintain the subsequent 2 to 10 year CBM values. Also, requirement R6 induces the question "subsequent to what?" Do we assume subsequent to R5's 13 months? We may be interpreting the requirement wrong. If so, please rephrase the requirement.<br><br>Response: The SDT has modified the VSLs to be clear that the duration referenced is related to the “lateness” of the determination, not the range to be calculated. In order to be clearer, the SDT has removed the word “subsequent” and redrafted the requirement as follows: “R6. At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used for planning purposes during each of the years two through ten following the current year.” |
| Response: Please see in-line responses. | | |
| ISO/RTO Council | No | We agree with all VSLs except the following:<br><br>R2: The structure of R2 is fine, but the identification of "late" notification of changes to CBMID needs to be based upon some specific time frame requirement in R2, which is absent in this draft standard. Please see our related comments under Q6. Further, the second condition for the HIGH VSL is loose. It assigns a HIGH to the TSP if it made available the CBMID to "some", but not all, of the entities specified in R2. "Some" needs to be more specific as otherwise, it will be a basis for argument in an audit process. Suggest to expand and grade the second condition VSLs by 1, 2, 3 and 4 or more for Low, Medium, High and Severe.<br><br>Response: The “late” criterion is not absent from the Requirement; the requirement states that notification must occur “before” the effective date of the change. Any notification that is not “before” that date is covered by the VSL and graded on “lateness.” To be clearer, the SDT has replaced the word “some” with “at least one.”<br><br>R7: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here.<br><br>Response: To be clearer, the SDT has replaced the word “some” with “at least one.” |

| Individual/Group | Question 4: | Question 4 Comments: |
|---|---|---|
| | | R8: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. Response: To be clearer, the SDT has replaced the word "some" with "at least one." <br><br> R9: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. In this case, the graded VSLs can be based on the percentage of total data requested. <br><br> Response: To be clearer, the SDT has replaced the word "some" with "at least one." The SDT believes that the "percentage of total data requested" would be somewhat difficult to measure. |
| Response: Please see in-line responses. | | |
| Ontario IESO | No | We agree with all VSLs except the following: <br><br> R2: The structure of R2 is fine, but the identification of "late" notification of changes to CBMID needs to be based upon some specific time frame requirement in R2, which is absent in this draft standard. Please see our related comments under Q6. Further, the second condition for the HIGH VSL is loose. It assigns a HIGH to the TSP if it made available the CBMID to "some", but not all, of the entities specified in R2. "Some" needs to be more specific as otherwise, it will be a basis for argument in an audit process. Suggest to expand and grade the second condition VSLs by 1, 2, 3 and 4 or more for Low, Medium, High and Severe. <br><br> Response: The "late" criterion is not absent from the Requirement; the requirement states that notification must occur "before" the effective date of the change. Any notification that is not "before" that date is covered by the VSL and graded on "lateness." To be clearer, the SDT has replaced the word "some" with "at least one." <br><br> R7: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. Response: To be clearer, the SDT has replaced the word "some" with "at least one." <br><br> R8: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. Response: To be clearer, the SDT has replaced the word "some" with "at least one." <br><br> R9: Same comment and suggestion for R2 on the assignment of HIGH based on "some" also applies here. In this case, the graded VSLs can be based on the percentage of total data requested. <br><br> Response: To be clearer, the SDT has replaced the word "some" with "at least one." The SDT believes that |

| Individual/Group | Question 4: | Question 4 Comments: |
|---|---|---|
| | | the “percentage of total data requested” would be somewhat difficult to measure. |
| Response: Please see in-line responses. | | |
| NPCC SRC | Yes | |
| Duke Energy Corporation | Yes | |
| Midwest ISO, Inc. | Yes | |
| PJM Interconnection, L.L.C. | Yes | |
| American Transmission Company | Yes | |
| ERCOT | No preference | At present, ERCOT does not use the concept of CBM in its operating activities. Therefore, I do not feel it would be appropriate for me to comment upon the VSLs. I believe that ATC, TTC, AFC, CBM, and TRM are concepts that apply to the operation of a Transmission Service Market and do not have an associated reliability function if such a market is not in use. |
| Response: If ERCOT does not use the concept of CBM, this standard would not apply to ERCOT. | | |
| Electric Power Supply Association | No preference | |
| MidAmerican Energy | No preference | |
| MEAG Power | No preference | |
| Bonneville Power Administration | No preference | |

5. The drafting team has modified the measures and compliance elements for MOD-004 based on industry comments. Do you believe these changes to the measures and compliance elements are appropriate? If "No," please identify your concerns.

**Summary Consideration:** Most entities were supportive of the measures and compliance.

One entity asked for limits to be placed on the data retention for R1; the SDT did so by updating the data retention to" the most recent three calendar years plus the current year."

One entity suggested movement of some explanatory text relted to the use of zero values to form he measure to the requirement; the SDT believes the requirement already allows for zero values, and that this inclusion in the measure is intended to make it clear to an auditor when measuring compliance that the intent of the drafting team was to allow the use of zero values. That entity also pointed out that Measure 10 did not allow for the consideration of an EEA3; the SDT modified the language to allow for that consideration.

| Individual/Group | Question 5: | Question 5 Comments: |
|---|---|---|
| Duke Energy Corporation | No | Section 1.3 Data Retention, first bullet should identify a maximum retention period, such as the most recent three calendar years plus the current year. |
| Response: The SDT has revised the standard to state, "for the most recent three calendar years plus the current year" to address this concern. | | |
| FirstEnergy Corp. | No | M6 - The phrase "(Note that CBM values may legitimately be zero)" should be removed from the measures and be integrated into the requirements.<br><br>Response: The SDT believes the requirement already allows for zero values; this inclusion in the measure is intended to make it clear to an auditor when measuring compliance that the intent of the drafting team was to allow the use of zero values.<br><br>M10 - The end of the statement in the measure should say "EEA 2 or higher".<br><br>Response: The SDT has modified the language to incorporate the words "or higher." |
| Response: Please see in-line responses. | | |
| ERCOT | No preference | At present, ERCOT does not use the concept of CBM in its operating activities. Therefore, I do not feel it would be appropriate for me to comment upon the measures and compliance elements. I believe that ATC, TTC, AFC, CBM, and TRM are concepts that apply to the operation of a Transmission Service Market and do not have an associated reliability function if such a market is not in use. |
| Response: If ERCOT does not use the concept of CBM, this standard would not apply to ERCOT. | | |
| NPCC SRC | Yes | |
| Salt River Project | Yes | |

| Individual/Group | Question 5: | Question 5 Comments: |
|---|---|---|
| Midwest ISO, Inc. | Yes | |
| PJM Interconnection, L.L.C. | Yes | |
| ISO/RTO Council | Yes | |
| Ontario IESO | Yes | |
| American Transmission Company | Yes | |
| Electric Power Supply Association | No preference | |
| MidAmerican Energy | No preference | |
| MEAG Power | No preference | |
| Hydro One Networks | Yes | |
| Bonneville Power Administration | No preference | |

6. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-004.

**Summary Consideration:**

One entity suggested that the NERC standards were requiring CBM to be treated on a first-come, first served basis. As CBM is a margin, the SDT believes that the first entity that needs CBM should be allowed to use it. If a conflict arises due to competing needs, the SDT believes it is up to tariffs and/or business practices to determine the appropriate way to manage the conflict. The SDT has expanded R1.3 to require an explanation of how competing requests for use of CBM are handled.

One entity requested that the phrase "to meet their need" be removed from R7, R8, M7 and M8, as this implied assignment of CBM like a reservation. The SDT removed the language.

One entity identified a problem where TSP boundaries and BA boundaries were not consistent. The SDT modified the standard to address the commenter's concern by modifying R12.3 to read as follows: "The Load of the Energy Deficient Entity is located within the Transmission Service Provider's area."

Several entities provided detailed questions with regard to Requirement 6. After careful review, the SDT determined that the providers' underlying concerns could be addressed with the current standards language, provided that it was clear in the measure that the practices employed by those entities were acceptable. The SDT has modified measure M6 to address this concern by adding the following sentence: "Inclusion of GCIR based on R6.1 and R6.2 within the transmission base case meets this requirement."

Two entities seemed to believe that CBM was required. The SDT directed those entities to the language in Order 890-A that indicated CBM was not required.

One entity pointed out that the standard indicated that only one study could be used to determine GCIR. The SDT modified R4.1 to allow for the use of multiple methods.

Several entities questioned the location of the requirements related to the use of CBM; some suggested they be moved to the INT standards, while other suggested they be moved to the EOP standards. The SDT has incorporated these requirements into this standard, as they are directly related to CBM. Additionally, the INT and EOP standards are outside the scope of this effort as defined by its SAR. Until such time as a SAR is submitted to move the requirements from this standard to another set of standards, we believe it is more important to have the requirements approved and enforceable.

Some entities suggested changes to the timeframes for lateness in R2, and requirement of a specific time ahead of a change for notification. The SDT explained that there are situations where rapid changes to the CBMID or its implementation could be required, and that limitations as suggested could delay entities from making those changes.

One entity suggested that R9 include a provision that restricts data "subject to confidentiality and security requirements." The SDT incorporated the suggested language.

| Individual/Group | Question 6 Comments: |
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| Electric Power Supply Association | In the following areas, EPSA believes that additional specificity in the standard would be beneficial.<br><br>– The update frequency for specifying the quantities of CBM to be withheld (see question 3 above)<br><br>Response: Through previous drafts and comments, the SDT has identified that the industry believes a less frequent review is appropriate.<br><br>– R3.1 specifies certain types of studies that are appropriate for the determination of CBM to be requested, for example LOLP studies. However, no guidance is provided on the appropriate target reliability. For example is 1 day in 10 years appropriate or 1 day in 100 years.<br><br>Response: The SDT believes this is generally specified by regulatory authorities, and is outside the scope of the SAR.<br><br>– R3.2 requires the purchaser of CBM to specify the import paths or source region for the CBM. Is there any ability for the TSP to alter this request? If so, on what basis? On what frequency should this information be updated?<br><br>Response: Requirements 5.2 and 6.2 state that the Transmission Service Provider and Transmission Planner must utilize the import paths or source regions during it's CBM allocation. The SDT believes this does not allow changes to the CBM requests; in the case where a specific source or path did not have sufficient capacity to be set aside, the Transmission Service Provider and/or Transmission Planner would have to communicate this back to the requestor, and that requestor would need to identify an alternate source or path.<br><br>– In R12 there is no indication of a priority level when CBM is requested by multiple LSEs in an EEA 2 and less than the full requested amount is available. Is the CBM granted to the LSE that had requested that it be set aside (R3)? Is it merely first come first served? Under this scenario, where a single contingency prompts a request for CBM from multiple LSEs, this suggests that it would be granted to the LSE that completes the paper work most quickly. |

| Individual/Group | Question 6 Comments: |
|---|---|
| | Response: As CBM is a margin, the SDT believes that the first entity that needs CBM should be allowed to use it. If a conflict arises due to competing needs, the SDT believes it is up to tariffs and/or business practices to determine the appropriate way to manage the conflict. The SDT has expanded R1.3 to require an explanation of how competing request for use of CBM are handled. |
| Response: Please see in-line responses. | |
| Duke Energy Corporation | In Requirements R7 and R8, and Measures M7 and M8 the phrase "to meet their need" should be struck. This phrase implies that the CBM set-aside would be assigned/allocated to specific LSEs and Resource Planners, which is not the case. |
| Response: The SDT has eliminated the phrase as suggested. | |
| MidAmerican Energy | NERC needs to develop clear standards for how the CBM value shall be determined, allocated across transmission paths, and used. The current standard does not require that to happen. |
| Response: The SDT has attempted to draft the standard such that it is compatible with many other previously approved implementations of CBM. The SDT believes that the standard provides guidance regarding the attributes of the calculation without being overly prescriptive | |
| MEAG Power | I wish to thank the SDT for its consideration of comments I submitted previously. Others at MEAG Power may choose to comment on other aspects of this standard; however, I comment solely to request that the SDT reconsider the wording of R12.3 in light of the fact that no Balancing Authority IS LOCATED WITHIN MEAG Power's service area. More specifically, MEAG Power's transmission system provides network service from network resources in Georgia to the loads of 48 cities and one county in Georgia. MEAG Power owns no transmission facilities outside of Georgia even though its system operates within the (multi-state) Southern Company Balancing Authority pursuant to a FERC-approved contract. Thus, MEAG Power is incapable of providing CBM to substantial amounts of load located within our host balancing authority (e.g., load located in Mississippi, Alabama and Florida). While it may not be typical for a TSP's service area to be a subset of its host balancing authority's footprint, I believe there are some others in this situation. Therefore, please consider if the following alternative wording would be suitable: R12.3 The energy deficient entity in the Balancing Authority with the EEA 2 has load located within the Transmission Service Provider's area. |
| Response: The SDT has clarified the requirement to meet the intent of your suggestion. R12.3 now reads as follows: "The Load of the Energy Deficient Entity is located within the Transmission Service Provider's area." | |
| Salt River Project | No other comments to offer. |
| Midwest ISO, Inc. | R6: Can the SDT clarify the intent of "planning purposes during the subsequent years two through ten." Does this refer to transmission expansion planning or long term TSR planning? The Midwest ISO believes the intent is for transmission expansion planning. If this is true, then we believe that establishing/using a predetermined CBM value per path or flowgate should not be the only way to account for LOLE in the planning process. The Midwest ISO, through Module E of its Tariff, conducts Resource Adequacy studies to determine the total amount of generation available in its footprint and then derive the total amount of power remaining to satisfy its LOLE requirements. This remaining power can be accounted for by building additional transmission in order to |

| Individual/Group | Question 6 Comments: |
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| | import or new generation can be built to meet the remaining power requirement. The Midwest ISO calculates CBM values for flowgates based on the remaining power requirement for short term (less than a year) ATC calculations. The Midwest ISO processes for Resource Adequacy and CBM Methodology have been through a Stakeholder process. We ask the SDT to consider the following language change:<br><br>R6: The Transmission Planner shall establish a predetermined CBM value for each ATC Path or Flowgate or GCIR for each designated area to be used for future transmission planning during the subsequent years two through ten.<br><br>R6.1 CBM and GCIR values shall reflect consideration of each of the following if available:<br>•Any studies (as described in R3.1) performed by Load-Serving Entities for loads within the Transmission Planner's area<br>•Any studies (as described in R4.1) performed by Resource Planners for loads within the Transmission Planner's area<br>•Any reserve margin or resource adequacy requirements for loads within the Transmission Planner's area established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operations, Regional Reliability Organizations, or regional entities<br><br>R6.2 Predetermined CBM values shall be allocated as follows:<br>•For ATC Paths, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners<br>•For Flowgates, based on the expected import paths or source regions provided by Load-Serving Entities or Resource Planners and the distribution factors associated with those paths or regions, as determined by the Transmission Planner<br><br>R6.3 Entities that do not utilize a predetermined CBM value in their respective planning process shall describe in their CBMID how the GCIR is calculated for each area and how the GCIR is used to calculate CBM values for ATC paths or Flowgates for selling transmission service.<br><br>Response: The SDT has modified measure M6 to address this concern by adding the following sentence: "Inclusion of GCIR based on R6.1 and R6.2 within the transmission base case meets this requirement."<br><br>R8: The Midwest ISO believes this requirement will also need modification based on our comments and proposed revision to R6. Please consider the language below:<br><br>R8. Less than 31 calendar days after the establishment of CBM or GCIR, the Transmission Planner shall notify |

| Individual/Group | Question 6 Comments: |
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| | all the Load-Serving Entities and Resource Planners that determined they had a need for CBM on the system being planned by the Transmission Planner of the amount of CBM set aside or the GCIR required to meet their resource adequacy requirements.<br>Response: the SDT believes that entities will need to convert GCIR into CBM. Accordingly, the SDT does not believe changes to the requirement are needed. |
| Response: Please see in-line responses. | |
| FirstEnergy Corp. | 1. We question how the TSP can "elect" to maintain CBM per R1. What if, per R3, the LSE determined they had a need to set aside transmission capacity as CBM but their TSP does not maintain CBM? Per FERC Orders 890 and 693, the LSE has the right to request CBM be set aside if it can prove that it is a critical need based on LOLE, deterministic studies, historical data, etc. as described in R3. We suggest revising the first part of the first sentence of R1 to state "The Transmission Service Provider that has been asked by its LSE or RP to maintain CBM?".<br><br>Response: Paragraph 82 of FERC Order 890-A states "The Commission clarifies in response to Duke that utilities do not need to make CBM available to LSEs on their system if the utilities do not reserve for themselves CBM or its equivalent." Accordingly, we have written the requirements and applicability such that only entities who maintain a CBM are required to follow this standard.<br><br>2. Per R3 and R4, it is not clear how GCIR is used in the CBM process. Is it merely equal to the CBM value or is it somehow used by the TSP to determine how much CBM is needed for each ATC Path or Flowgate? Either way, the standard should explain what is done with the GCIR once it has been established.<br><br>Response: The SDT chose not to be overly prescriptive regarding how GCIR would be used. GCIR may be used to determine the CBM, or may be used as the CBM, depending on the manner in which the entity implements CBM and the specific ATC methodology chosen.<br><br>3. In R3.1 and R4.1, can the LSE and RP use different studies for different ATC Paths or Flowgates? If so, then R3.1 and R4.1 should be revised to state "Using one of the following for each ATC Path or Flowgate to determine the GCIR:".<br><br>Response: The SDT has modified the language of the requirements to allow for the use of multiple approaches for determining GCIR.<br><br>4. With regard to R3 and the responsibilities of the LSE, currently many LSEs work with their TSP to determine the need for CBM because most LSEs do not have the capability to undertake these studies on their own. In addition, several LSEs participate within a Planned Resource Sharing Group that works with that sharing |

| Individual/Group | Question 6 Comments: |
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| | group's TSP to determine the need for CBM. We assume that these activities would be permitted to continue and that this standard will not preclude LSEs from working with their TSP to determine CBM needs. We ask the SDT to confirm our assumptions.<br><br>Response: We believe that entities using a Planned Resource Sharing Group should be able to continue to do so by either 1.) working with their Resource Planner, or 2.) registering as a Joint Registration Organization. |
| Response: Please see in-line responses. | |
| Hydro One Networks | Effective Date:<br><br>We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in standards that have a clear reliability impact. In addition, it does not seem appropriate to have entities exposed to sanctions for non-compliance in some jurisdictions while not in others.<br><br>The words inserted in the Effective Date of the Standards as well as in the Implementation Plan posted documents permit that these Standards are effective in some jurisdictions and not others. The Standard and the Implementation Plan should be modified to ensure that they become effective in all jurisdictions at the same time, including those where such regulatory approval in not required, that is, only when all regulatory approvals have been obtained. We suggest the same words used in MOD-001, 28, 29 and 30 be used:<br><br>"All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by all applicable regulatory authorities."<br><br>Response: The SDT believes that in this case, it is not critical from a relativity perspective to implement this standard concurrently across North America. Note that there is already a CBM standard in place; until such time as this standard is approved, that standard will remain in effect.<br><br>R11 and R12: We think these requirements belong in the INT standards, which deals with reliability assessment of Arranged Interchange.<br><br>Response: The SDT has incorporated these requirements into this standard, as they are directly related to CBM. Additionally, the INT standards are outside the scope of this effort as defined by its SAR. Until such time as a SAR is submitted to move the requirements from this standard to another set of standards, we believe it is more important to have the requirements approved and enforceable. |

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<tr><th>Individual/Group</th><th>Question 6 Comments:</th></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>PJM Interconnection, L.L.C.</td><td>PJM submits the following comments for consideration. PJM proposes revising Requirement 6 as follows:<br><br>R6 - At least every 13 months, the Transmission Planner shall establish a CBM value for each ATC Path or Flowgate to be used during the subsequent years 2 through 10. This value shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]<br><br>PJM proposes the addition of a new Requirement 7 as follows:<br><br>New R7 - At least every 13 months, the Transmission Planner shall establish a CBM value to be used for planning purposes during the subsequent years 2 through 10. This value shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]<br><br>Response: The SDT interprets this comment to mean that PJM believes that planning may utilize a GCIR value rather than a specific path-based CBM. The SDT has modified measure M6 to address this concern by adding the following sentence: “Inclusion of GCIR based on R6.1 and R6.2 within the transmission base case meets this requirement.”<br><br>PJM agrees that Requirements 10, 11 and 12 are essential. PJM identifies these requirements as addressing emergency scenarios. PJM proposes that it is more appropriate to include these requirements in EOP-002, Attachment 1 which governs emergency operations.<br><br>Response: The SDT has incorporated these requirements into this standard, as they are directly related to CBM. Additionally, the EOP standards are outside the scope of this effort as defined by its SAR. Until such time as a SAR is submitted to move the requirements from this standard to another set of standards, we believe it is more important to have the requirements approved and enforceable.</td></tr>
<tr><td colspan="2">Response: Please see in-line responses.</td></tr>
<tr><td>ISO/RTO Council</td><td>R2: It requires the TSP to notify those entities of any changes to the CBMID prior to the effective date of the change. There should be a time frame specified for the notification to tighten up the requirement and facilitate proper development of measures and VSLs. Given that the changes affect the CBMID, we'd think that a period of 7 to 30 days would be appropriate.<br><br>Response: The SDT believes that there are situations where rapid changes to the CBMID or its implementation could be required, and that limitations as suggested could delay entities from making those changes. Accordingly, the SDT did not elect to specify a minimum notice period for the requirement. Based on previous comments, the SDT has modified R2 to refer to the “effective date” rather than simply “the</td></tr>
</table>

| Individual/Group | Question 6 Comments: |
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| | change."<br><br>R9: It requires the TSP and TP to provide copies of the supporting data, including any models, used for determining CBM to a number of entities. It should be noted that some of these requesting entities may have commercial interests or affiliations. Further, in some established markets or jurisdictions, the TSPs and/or the TPs may not be able to provide such data, especially the model, to a third party. We suggest this requirement be qualified by adding "subject to confidentiality and security requirements" as in MOD-001, R8.<br><br>Response: The SDT has modified R9 to include the suggested language.<br><br>R11 and R12: We think these 2 requirements should be moved to INT-006 which deals with reliability assessment of Arranged Interchange. The draft INT-006 being posted for comments deals specifically with emergency requests (and reliability adjustment requests).<br><br>Response: The SDT has incorporated these requirements into this standard, as they are directly related to CBM. Additionally, the INT standards are outside the scope of this effort as defined by its SAR. Until such time as a SAR is submitted to move the requirements from this standard to another set of standards, we believe it is more important to have the requirements approved and enforceable. |
| Response: Please see in-line responses. | |
| Ontario IESO | R2: It requires the TSP to notify those entities of any changes to the CBMID prior to the effective date of the change. There should be a time frame specified for the notification to tighten up the requirement and facilitate proper development of measures and VSLs. Given that the changes affect the CBMID, we'd think that a period of 7 to 30 days would be appropriate.<br><br>Response: The SDT believes that there are situations where rapid changes to the CBMID or its implementation could be required, and that limitations as suggested could delay entities from making those changes. Accordingly, the SDT did not elect to specify a minimum notice period for the requirement. Based on previous comments, the SDT has modified R2 to refer to the "effective date" rather than simply "the change."<br><br>R9: It requires the TSP and TP to provide copies of the supporting data, including any models, used for determining CBM to a number of entities. It should be noted that some of these requesting entities may have commercial interests or affiliations. Further, in some established markets or jurisdictions, the TSPs and/or the TPs may not be able to provide such data, especially the model, to a third party. We suggest this requirement be qualified by adding "subject to confidentiality and security requirements" as in MOD-001, R8. |

| Individual/Group | Question 6 Comments: |
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| | Response: The SDT has modified R9 to include the suggested language.<br><br>R11 and R12: We think these 2 requirements should be moved to INT-006 which deals with reliability assessment of Arranged Interchange. The draft INT-006 being posted for comments deals specifically with emergency requests (and reliability adjustment requests).<br><br>Response: The SDT has incorporated these requirements into this standard, as they are directly related to CBM. Additionally, the INT standards are outside the scope of this effort as defined by its SAR. Until such time as a SAR is submitted to move the requirements from this standard to another set of standards, we believe it is more important to have the requirements approved and enforceable. |
| Response: Please see in-line responses. | |
| American Transmission Company | 1. Due to the Midwest ISO methodology of calculating CBM in the short-term (1 year) and GCIR in the long-term, we believe that R6 should be changed to include: "GCIR for each designated area to be used for future transmission planning." and add the words "that maintains CBM" after "the Transmission Planner"<br><br>2. R6.1 should include "CBM and GCIR values shall reflect consideration of each of the following if available".<br><br>3. R6.3 should include "Entities that do not utilize a predetermined CBM value in their respective planning process shall describe in their CBMID how the GCIR is calculated for each area and how the GCIR is used to calculate CBM values for ATC paths or Flowgates for selling transmission service."<br><br>Response: The SDT interprets this comment to mean that ATC believes that planning may utilize a GCIR value rather than a specific path-based CBM. The SDT has modified measure M6 to address this concern by adding the following sentence: “Inclusion of GCIR based on R6.1 and R6.2 within the transmission base case meets this requirement.” Regarding the addition of the phrase “that maintains CBM,” the SDT has already included this language in the applicability section of the standard, so it is not required in R6.<br><br>4. R8 should include "Less than 31 calendar days after the establishment of CBM or GCIR, the Transmission Planner shall notify all the Load-Serving Entities and Resource Planners that determined they had a need for GCIR on the system being planned by the Transmission Planner of the amount of CBM set aside or the GCIR required to meet their need."<br><br>Response: the SDT believes that entities will need to convert GCIR into CBM in order to communicate it back to entities that requested it. Accordingly, the SDT does not believe changes to the requirement are needed.<br><br>5. Change the wording in 1.3 Data Retention to: "The Compliance Enforcement Authority shall keep the last |

| Individual/Group | Question 6 Comments: |
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| | audit records and all subsequent requested and submitted audit records."<br><br>Response: The SDT has modified the language to read as follows: "The Compliance Enforcement Authority shall keep the last audit records and all requested and subsequently submitted audit records." |
| Response: Please see in-line responses. | |
| Bonneville Power Administration | How would a generator in a neighboring Balancing Authority (or control area) provide the CBM due to a sudden generation outage in the host control area (or BA area) where the outage occurred? The CBM would be provided after the TRM and has been established as a reliability requirement by an LSE. The ATC DT should explain how this standard ensures that an LSE can replace the lost generation from a neighboring BA.<br><br>Response: This standard does not ensure that an LSE can replace the lost generation from a neighboring BA. It is intended to ensure that an LSE can import on its host system to replace that generation. All arrangements outside the host system should be managed by the entity needing the energy unless delegated to others.<br><br>New Section A.5. Effective date: On the third line, "become" should be "becomes" that is unless they intend to pluralize standard to be standards.<br><br>Response: The SDT has corrected the language as suggested.<br><br>CBM is a scheduled transmission reservation that is implemented following the expiration of the TRM. (TRM is unscheduled transmission capacity that can be used to implement emergency operations up to 59 minutes.)<br><br>Response: CBM is not a scheduled transmission reservation. CBM is a transmission margin set aside for potential future uses to import energy during an EEA2. The SDT does not agree that Reserves and the use of CBM are necessarily linked as the commenter seems to suggest.<br><br>Would like to suggest that that the scope of Project 2009-09, a Resource Adequacy Assessments Standard, which is slated for development in 2009, be enlarged to include aspects of MOD-004 that relate to defining the four analyses upon which the GCIR determination is based in greater detail. Although we agree that any one of these analyses is appropriate in calculating GCIR, we believe that these analyses need to be defined in greater detail in order to achieve the stated purpose of the standard. The stated purpose of this standard is: "To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations." The standard also states that the determination of Generation Capability Import Requirement (GCIR), which is the basis for the CBM request, can be calculated using any of the following analyses: (1) Loss of Load Expectation (LOLE) studies, (2) Loss of Load Probability (LOLP) studies, (3) Deterministic risk-analysis studies and (4) Reserve margin or resource adequacy |

| Individual/Group | Question 6 Comments: |
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| | requirements established by other entities, such as municipalities, state commissions, regional transmission organizations, independent system operators, Regional Reliability.<br><br>Response: The SDT suggests that the commenter submit a suggestion for inclusion in the development of NERC's Work Plan. Suggestions may be submitted through the Reliability Standards Suggestions and Comment Form: http://www.nerc.com/files/Standards_Input_Form_Final_2008June30.doc |
| Response: Please see in-line responses. | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Flowgate:**

1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

**Available Flowgate Capability (AFC):** A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs)on Flowgates.

   **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID). [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in AFC calculations including:

**R1.2.1.** Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Include Flowgates used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated

Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.** Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use first Contingency criteria consistent with those first Contignency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.3.** Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.
- The Transmission Operator may utilize distribution factors less than 5% if desired.

2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

**R2.2.** At a minimum, establish the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.

**R2.3.** At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

**R2.4.** Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, establish the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence"

representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.

- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:.

**R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider’s area.

**R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider’s area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

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[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{Fi}$** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**$AFC_{NF}$** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

**R11.** When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$TC = \min(P)$$

$$P = \{PTC_1, PTC_2, \ldots PTC_n\}$$

$$PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either ‘Available’ or ‘Total’).

**P** is the set of partial Transfer Capabilities (either available or total) for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**$PTC_n$** is the partial Transfer Capability (either ‘Available’ or ‘Total’) for a path relative to a Flowgate *n*.

**$FC_n$** is the Flowgate Capability (‘Available’ or ‘Total’) of a Flowgate *n*.

**$DF_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

**M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-030-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)

**M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)

**M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

**M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, it follows the procedure described in R11. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits

- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). |
| R2. | One or more of the following:<br>• The Transmission Operator established its list of internal Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.<br>• The Transmission Operator established its list of external Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete an external flowgate as described in R2.3.<br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more | One or more of the following:<br>• The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of internal Flowgates more than three months late, but not more than six months late as described in R2.2.<br>• The Transmission Operator established its list of external Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete an external flowgate | One or more of the following:<br>• The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of internal Flowgates more than six months late, but not more than nine months late as described in R2.2.<br>• The Transmission Operator established its list of external Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete an external flowgate as | One or more of the following:<br>• The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of internal Flowgates more than nine months late as described in R2.2.<br>• The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.<br>• The Transmission Operator established its list of external Flowgates more than 120 days following a request to create, modify or delete an external flowgate as described in R2.3. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | than 7 days, but it has not been more than 14 days since the notification (R2.5.1)<br><br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | as described in R2.3.<br><br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)<br><br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination. | described in R2.3.<br><br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. | • The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.<br><br>• The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.<br><br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)<br>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | One or more of the following:<br>• The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks | One or more of the following:<br>• The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks | One or more of the following:<br>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks | One or more  of the following:<br>• The Transmission Operator did not update the model per R3.2 for more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than ten weeks<br>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>• The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or more than 3 reservations, whichever is greater.. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | One or more of the following:<br>• The Transmission Service Provider did not use the model provided by the Transmission Operator.<br>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.<br>• The Transmission Service provider did not use AFC provided by a third party. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | greater). | greater). | |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |
| R10 | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. | described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | Transmission Service provider did not calculate for 28 or more calendar days. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs (and/or TFCs to TTCs) described in R11. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 3–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Flowgate:**

1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

**Available Flowgate Capability (AFC):** A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system F~~f~~acilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system F~~f~~acilities removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available ~~Transfer~~ Flowgate Capabilities (A~~T~~FCs)~~ for ATC Paths~~on Flowgates.

   **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates~~ATCs for ATC Paths~~.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID). [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in AFC calculations including:

**R1.2.1.** Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Include~~Identify~~ Flowgates used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use first Contingency ~~assumptions~~ criteria consistent with those first Contingenc~~ies~~y criteria used in planning of operations~~operations studies and planning studies~~ for the applicable time periods, including use of Special Protection Systems.

2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.** Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use first Contingency ~~assumptions~~ criteria consistent with those first Contignenc~~ies~~y criteria used in planning of operations~~operations studies and planning studies~~ for the applicable time periods, including use of Special Protection Systems.

2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.3.** Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. T~~If t~~he coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

2.1.4.2. T~~If t~~he limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

**R2.2.** At a minimum, establish the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.

**R2.3.** At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

**R2.4.** Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, establish the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and F~~f~~acilities161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the ~~period calculated~~applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.~~3~~4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.1.2.** Unit commitment and ~~dispatch~~ Dispatch ~~order~~Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:.

**R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.2.2.** Unit commitment and ~~dispatch~~ Dispatch ~~order~~Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.

**R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers~~,~~ and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{Fi}$** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**$AFC_{NF}$** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.~~3~~2, R3.~~4~~3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

**R11.** When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$TC = \min(P)$$

$$P = \{PTC_1, PTC_2, \ldots PTC_n\}$$

$$PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either 'Available' or 'Total').

**P** is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**$PTC_n$** is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n.*

**$FC_n$** is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

**$DF_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in ~~that are to be considered in~~ AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs) that it ~~updated~~ established the TFCs for each Flowgate in accordance with the timing defined in R2.5~~at least once per calendar year~~. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

**M13.** The Transmission Service Provider~~TSP~~ ~~must be capable of~~shall demonstrate~~ing~~ ~~that for any calculation of firm ETC made in the previous sixty days, the Transmission Service Provider can~~compliance with R6 by recalculating~~e~~ ~~the individual value of the~~ firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate ~~this~~ the specified value for the designated ~~hour~~time period. The data used must meet the requirements specified in ~~the standard~~MOD-030-1 and the ATCID.~~,~~ To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is ~~and the audited value must be~~ within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC~~demonstrated result~~. (R6)

**M14.** The Transmission Service Provider~~TSP~~ ~~must be capable of~~shall demonstrate~~ing~~ ~~that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can~~compliance with R7 by recalculating~~e~~ ~~the individual value of the~~ non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate ~~this~~ the specified value for the designated ~~hour~~time period. The data used must meet the requirements specified in the standard and the ATCID. ~~, and the audited value must be~~ To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC~~demonstrated result~~. (R7)

**M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

**M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated ~~ATC~~ AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, it~~that the determination of Transfer Capabilities~~ follows the procedure described in R11. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Data Retention**

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to ~~to~~ determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in ~~with~~ R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.

- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). |
| R2. | One or more of the following:<br>• The Transmission Operator established its list of internal Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.<br>~~**OR**~~<br>• The Transmission Operator established its list of external Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete an external flowgate as described in R2.3.<br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more | One or more of the following:<br>• The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>~~**OR**~~<br>• The Transmission Operator established its list of internal Flowgates more than three months late, but not more than six months late as described in R2.2.<br>~~**OR**~~<br>• The Transmission Operator established its list of external Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete an external flowgate | One or more of the following:<br>• The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>~~**OR**~~<br>• The Transmission Operator established its list of internal Flowgates more than six months late, but not more than nine months late as described in R2.2.<br>~~**OR**~~<br>• The Transmission Operator established its list of external Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete an | One or more of the following:<br>• The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of internal Flowgates more than nine months late as described in R2.2.<br>~~OR~~<br>• The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.<br>~~OR~~<br>• The Transmission Operator established its list of external Flowgates more than 120 |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | than 7 days, but it has not been more than 14 days since the notification (R2.5.1)<br><br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | as described in R2.3.<br><br>~~OR~~<br><br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br><br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)<br><br>~~OR~~<br><br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination. | external flowgate as described in R2.3.<br><br>~~OR~~<br><br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br><br>~~OR~~<br><br>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)<br><br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. | days following a request to create, modify or delete an external flowgate as described in R2.3.<br><br>~~OR~~<br><br>• The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.<br><br>~~OR~~<br><br>~~The Transmission Operator has not updated its list of internal Flowgates for two or more consecutive years.~~<br><br>~~OR~~<br><br>• The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.<br><br>~~OR~~<br><br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)<br><br>~~OR~~ |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | • The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)<br>~~OR~~<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination. |
| R3. | One or more of the following:<br>• The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks | One or more of the following:<br>• The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks | One or more of the following:<br>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks | One or more of the following:<br>• The Transmission Operator did not update the model per R3.2 for more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than ten weeks<br>~~The Transmission Operator used a Transmission model that had not been updated per the schedule specified in R3.~~<br>~~OR~~<br>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | ~~Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled.~~ | ~~Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled.~~ | ~~Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled.~~ | Transmission or Generator Owner in their Transmission model.<br>~~OR~~<br>• The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>~~OR~~<br>• The Transmission operator did not include in the Transmission ~~model detailed~~ modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.~~at least three contiguous busses of the BES for more than one adjacent Reliability Coordinator area~~.<br>~~Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled.~~ |
| R4. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater.. | 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater.. | 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater.. | more than 3 reservations, whichever is greater.. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | One or more of the following:<br>• The Transmission Service Provider did not use the model provided by the Transmission Operator.<br>~~OR~~<br>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.<br>~~OR~~<br>• The Transmission Service provider did not use AFC provided by a third party. |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.. | whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | whichever is greater. |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater). | Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | Flowgates or more than 3 Flowgates (whichever is greater). |
| R10 | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.<br>~~For Hourly, the Transmission Service provider did not calculate for more than 24~~ | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.<br>~~For Hourly, the Transmission Service provider did not calculate for more than 48~~ | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.<br>~~For Hourly, the Transmission Service provider did not~~ | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.<br>~~For Hourly, the Transmission Service provider did not calculate for more than 96 hours.~~<br>~~**OR**~~ |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | ~~hours but not more than 48 hours.~~<br>~~**OR**~~<br>~~For Daily, the Transmission Service provider did not calculate for more than 7 calendar days but not more than 14 calendar days.~~<br>~~**OR**~~<br>~~For Monthly, the Transmission Service provider did not calculate for 31 or more calendar days, but less than 60 calendar days.~~ | ~~hours but not more than 72 hours.~~<br>~~**OR**~~<br>~~For Daily, the Transmission Service provider did not calculate for more than 14 calendar days but not more than 21 calendar days.~~<br>~~**OR**~~<br>~~For Monthly, the Transmission Service provider did not calculate for 60 or more calendar days, but less than 90 calendar days.~~ | ~~calculate for more than 72 hours but not more than 96 hours.~~<br>~~**OR**~~<br>~~For Daily, the Transmission Service provider did not calculate for more than 21 calendar days but not more than 28 calendar days.~~<br>~~**OR**~~<br>~~For Monthly, the Transmission Service provider did not calculate for 90 or more calendar days, but less than 120 calendar days.~~ | ~~For Daily, the Transmission Service provider did not calculate for more than 28 calendar days.~~<br>~~**OR**~~<br>~~For Monthly, the Transmission Service provider did not calculate for 120 or more calendar days.~~ |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs (and/or TFCs to TTCs) ~~determining Transfer Capabilities~~ described in R11. |

## Implementation Plan for Standard MOD-030 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-030 — Flowgate Methodology, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining AFC.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### Modified Standards

This standard incorporates the following requirements from FAC-012:

– R1 (Documentation of the Transfer Capability Methodology)

– R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board. As such, FAC-012 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013:

– R1 (Calculation of the Transfer Capabilities)

– R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013 is no longer needed and is being retired.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-030 | ■ | | ■ | | | |

### Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001, MOD-028, MOD-029, and MOD-030) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to

implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Implementation Plan for Standard MOD-030 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-030 — Flowgate Methodology, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining AFC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard incorporates the following requirements from FAC-012:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board. As such, FAC-012 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-030 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001, MOD-028, MOD-029, and MOD-030) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to

implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Summary of Process Steps Taken Following Posting of the Standards for 30-day Comment

The ATC Standard Drafting Team is developing the ATC-related standards, in part, as a response to FERC Order 890. Order 890 provided specific guidance on the timeliness of this standards development effort. The drafting team has been working to a strict time line to ensure it can file these standards in compliance with the Commission's directives, while also adhering to the NERC Reliability Standards Development Procedure.

As described in Step 8 of NERC's Reliability Standards Development Procedure,

> "Based on the comments received and field testing, the standard drafting team may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the effect or use of the standard."

When reviewing the comments received and considering changes to the standards, the drafting team also considered that any substantive changes to the requirements would require an additional 30-day comment and response period, which would eliminate the possibility of meeting the FERC's submission deadlines. The drafting team carefully weighed the reliability benefit of any changes to the standard, and attempted to limit its modifications to those that clarify or explain, rather than create new requirements or change intent. The changes to the standards made by the drafting team fall into one or more of the following categories:

- Corrections
- Redrafting of language that does not change intent
- Clarifications that better explain intent
- Modifications that change minor details, but not intent
- Modifications to ensure consistency and reduce ambiguity

The drafting team does not believe that any of the changes made to the requirements following the last comment period directly or materially affect the effect or use of the standards, but instead make the standards more clear.

The NERC Standards Committee is a stakeholder group responsible for the oversight of standards development, including evaluation of the responses to comments and any changes to the standards. As described in Step 8 of NERC's Reliability Standards Development Procedure:

> "When the Standards Committee receives a draft standard that is recommended for ballot, the Standards Committee will review the standard and recommendations of the standards process manager to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives and requirements cited in Steps 1 to 8, as applicable; has an implementation plan; and is compatible with other existing standards. If the proposed standard does not pass this review, the Standards Committee shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the Standards

Committee shall set the proposed standard for ballot as soon as the work flow will accommodate.”

NERC’s Standards Process Manager presented the changes described above to the Executive Committee of the NERC Standards Committee on June 19, 2008.  Following review of the revisions made to the standards, comment responses, and implementation plans, the Standards Committee’s Executive Committee determined that the standards had passed the review, and the changes made do not directly or materially affect the effect or use of the standards.  The Standards Committee’s Executive Committee directed NERC’s Standards Process Manager to post the standards for 30-day pre-ballot review and to begin assembling the ballot pools necessary for balloting.

## Reliability Standards



| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC et al Standard - MOD-030_in |
| **Ballot Period:** | 7/21/2008 - 7/30/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 218 |
| **Total Ballot Pool:** | 231 |
| **Quorum:** | **94.37 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 56.56 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

**Summary of Ballot Results**

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 64 | 1 | 19 | 0.463 | 22 | 0.537 | 18 | 5 |
| 2 - Segment 2. | 9 | 0.5 | 4 | 0.4 | 1 | 0.1 | 3 | 1 |
| 3 - Segment 3. | 65 | 1 | 25 | 0.463 | 29 | 0.537 | 9 | 2 |
| 4 - Segment 4. | 14 | 1 | 2 | 0.182 | 9 | 0.818 | 3 | 0 |
| 5 - Segment 5. | 36 | 1 | 17 | 0.654 | 9 | 0.346 | 8 | 2 |
| 6 - Segment 6. | 27 | 1 | 12 | 0.571 | 9 | 0.429 | 4 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 3 | 0.2 | 2 | 0.2 | 0 | 0 | 1 | 0 |
| 9 - Segment 9. | 5 | 0.4 | 4 | 0.4 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.5 | 4 | 0.4 | 1 | 0.1 | 2 | 0 |
| **Totals** | **231** | **6.6** | **89** | **3.733** | **80** | **2.867** | **49** | **13** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Ameren Services Company | Kirit S. Shah | Negative | View |
| 1 | American Electric Power | Paul B. Johnson | Affirmative | |
| 1 | American Transmission Company, LLC | Jason Shaver | Negative | View |
| 1 | Arizona Public Service Co. | Cary B. Deise | Abstain | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | | |
| 1 | Avista Corp. | Scott Kinney | Negative | View |
| 1 | Basin Electric Power Cooperative | David Rudolph | Negative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Negative | View |
| 1 | Brazos Electric Power Cooperative, Inc. | Tony Kroskey | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Abstain | |
| 1 | Central Lincoln PUD | Ronald Beck | Negative | View |
| 1 | Central Maine Power Company | Brian Conroy | | |
| | City of Tacoma, Department of Public | | | |

| | | | | |
|---|---|---|---|---|
| 1 | Utilities, Light Division, dba Tacoma Power | Alan L Cooke | Negative | View |
| 1 | City of Tallahassee | Gary S. Brinkworth | Abstain | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | E.ON U.S. LLC | Larry Monday | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Affirmative | |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Manitoba Hydro | Michelle Rheault | Negative | View |
| 1 | Minnesota Power, Inc. | Carol Gerou | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Abstain | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Negative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Abstain | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Affirmative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Negative | |
| 1 | PacifiCorp | Robert Williams | Negative | View |
| 1 | Platte River Power Authority | John C Collins | Abstain | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Negative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Negative | View |
| 1 | Progress Energy Carolinas | Sammy Roberts | Affirmative | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Abstain | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Abstain | |
| 1 | Salt River Project | Robert Kondziolka | Abstain | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Abstain | |
| 1 | Seattle City Light | Christopher M. Turner | Abstain | View |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Abstain | |
| 1 | Southern California Edison Co. | Dana Cabbell | Negative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Abstain | View |
| 1 | Transmission Agency of Northern California | James W Beck | Abstain | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Abstain | |
| 1 | Western Area Power Administration | Robert Temple | Negative | View |
| 1 | Western Farmers Electric Coop. | Alan Derichsweiler | | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | | |
| 2 | British Columbia Transmission Corporation | Phil Park | Abstain | |

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|---|---|---|---|---|
| 2 | California ISO | David Hawkins | Negative | View |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | View |
| 2 | New Brunswick System Operator | Alden Briggs | Affirmative | |
| 2 | New York Independent System Operator | Gregory Campoli | Abstain | |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Ameren Services Company | Mark Peters | Negative | View |
| 3 | American Electric Power | Raj Rana | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Negative | View |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Blachly-Lane Electric Co-op | Bud Tracy | Negative | View |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Negative | View |
| 3 | City of McMinnville | Rick Rozanski | Negative | View |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Negative | View |
| 3 | Clatskanie People's Utility District | Joseph Taffe | Negative | View |
| 3 | Clearwater Power Co. | Dave Hagen | Negative | View |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Constellation Energy | Carolyn Ingersoll | Affirmative | |
| 3 | Consumers Energy | David A. Lapinski | Abstain | |
| 3 | Coos-Curry Electric Cooperative, Inc | Roger Meader | Negative | View |
| 3 | Cowlitz County PUD | Russell A Noble | Negative | View |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | View |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Grays Harbor PUD | Wesley W Gray | Negative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Affirmative | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | |
| 3 | Lost River Electric Cooperative | Richard Reynolds | Negative | View |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Negative | View |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | Nevada Power Co. | Sheryl Torrey | Negative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Niagara Mohawk (National Grid Company) | Michael Schiavone | Affirmative | |
| 3 | Northern Indiana Public Service Co. | William SeDoris | Negative | |
| 3 | Northern Lights Inc. | Jon Shelby | Negative | View |
| 3 | Northern Wasco County People's Utility District (PUD) | Paul Titus | Negative | View |
| 3 | Okanogan County Electric Cooperative, Inc. | Ray Ellis | Negative | View |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Abstain | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Affirmative | |

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|---|---|---|---|---|
| 3 | Progress Energy Carolinas | Sam Waters | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Abstain | |
| 3 | Public Utility District No. 1 of Benton County | Gloria Bender | Negative | View |
| 3 | Public Utility District No. 1 of Franklin County | Linda Boomer | Abstain | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Negative | View |
| 3 | Raft River Rural Electric Cooperative | Heber Carpenter | Negative | View |
| 3 | Salmon River Electric Cooperative | Ken Dizes | Negative | View |
| 3 | Salt River Project | John T. Underhill | Abstain | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Abstain | View |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | | |
| 3 | Umatilla Electric Cooperative | Steve Eldrige | Negative | View |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | Alliant Energy Corp. Services, Inc. | Kenneth Goldsmith | Negative | View |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Eugene Water & Electric Board | Dean Ahlsten | Negative | View |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Affirmative | |
| 4 | Northern California Power Agency | Fred E. Young | Abstain | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Negative | |
| 4 | Pacific Northwest Generating Cooperative | Aleka K Scott | Negative | View |
| 4 | Public Power Council | Nancy Baker | Negative | View |
| 4 | Public Utility District No. 1 of Douglas County | Henry E. LuBean | Negative | View |
| 4 | Public Utility District No. 1 of Snohomish County | John D. Martinsen | Negative | View |
| 4 | Seattle City Light | Hao Li | Abstain | View |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 4 | WPS Resources Corp. | Christopher Plante | Negative | View |
| 5 | AEP Service Corp. | Brock Ondayko | Affirmative | |
| 5 | Avista Corp. | Edward F. Groce | Negative | View |
| 5 | Bonneville Power Administration | Francis J. Halpin | Negative | View |
| 5 | City of Farmington | Clinton J Jacobs | Affirmative | |
| 5 | City of Tallahassee | Alan Gale | Abstain | |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Affirmative | |
| 5 | Deseret Power | Philip B Tice Jr | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Affirmative | |
| 5 | Entergy Corporation | Stanley M Jaskot | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | IBERDROLA RENEWABLES | Laura Beane | Negative | View |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Negative | View |
| 5 | New York Power Authority | Gerald Mannarino | Affirmative | |
| 5 | Orlando Utilities Commission | Richard Kinas | Abstain | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Negative | View |
| 5 | Progress Energy Carolinas | Wayne Lewis | Affirmative | |

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| 5 | Salt River Project | Glen Reeves | Abstain | |
| 5 | Seattle City Light | Michael J. Haynes | Abstain | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | | |
| 5 | Southeastern Power Administration | Douglas Spencer | Affirmative | |
| 5 | Southern California Edison Co. | David Schiada | Abstain | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Abstain | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | U.S. Bureau of Reclamation | Martin Bauer | | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Affirmative | |
| 6 | AEP Marketing | Edward P. Cox | Affirmative | |
| 6 | Barry Green Consulting Inc. | Barry Green | Affirmative | |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Negative | View |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | IBERDROLA RENEWABLES | Kellie J Schreiner | Negative | View |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Negative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | Portland General Electric Co. | John Jamieson | Negative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Negative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Affirmative | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Negative | View |
| 6 | Salt River Project | Mike Hummel | Abstain | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | Southern California Edison Co. | Marcus V Lotto | Abstain | |
| 6 | Tampa Electric Co. | Jose Benjamin Quintas | | |
| 6 | Tenaska Power Services Co. | Cliff T Richardson | Abstain | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Affirmative | |
| 7 | Eastman Chemical Company | Lloyd Webb | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Abstain | |
| 8 | Other | Michehl R. Gent | Affirmative | |
| 8 | Volkmann Consulting | Terry Volkmann | Affirmative | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Abstain | View |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | SERC Reliability Corporation | Carter B Edge | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |

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| 10 | Western Electricity Coordinating Council | Louise McCarren | Abstain | |
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116-390 Village Boulevard, Princeton, New Jersey 08540-5721

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| Ameren Services Company | 1 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-030-1. (1) AFC is a market parameter and as such is applicable to the Transmission Service Provider. (2) Definition of an adequate flowgate population is required to adequately constrain the sale of transmission service, as such this would appear to be a market not a reliability issue. (3) Under R2 the calculation of TFC is applicable to the Transmission Operator. This is not consistent with the current version of the Functional Model. The Transmission Planner is responsible for supporting the development of TTC (TFC). (3) Under R3 the Transmission Service Provider not the Transmission Operator should be responsible for the calculation of ATC/AFC and any modeling data. This is especially true when the Transmission Service Provider determines ATC for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO. (4) That said we are aware that the oversubscription of transmission service can lead to reliability problems. (5)AFC issues affect long term planning as well as planning in the Operating Time Horizon. |
| American Transmission Company, LLC | 1 | Negative | R2.1.3: Midwest ISO believes that this requirement is too onerous and leaves no allowance for an Interconnection-wide congestion management process to be enacted due to a forced outage or any other system condition unforeseen by forecasted system conditions. Also, the SDT did not respond to Midwest ISO comment concerning temporary flowgates in TLR. Midwest ISO questions the reliability benefit gained by calculating AFCs for a flowgate which was only created for a temporary system condition. Midwest ISO also believes that a flowgate referenced by R3.5 should be added by process established in R2.1.4. Otherwise, as the requirement is written, if a forced outage causes an Interconnection-wide congestion management procedure to be enacted in on a limiting element/contingency in PJM, then Midwest ISO would be required to add that facility as a flowgate despite the opinion of PJM or even if a transfer from Midwest ISO to PJM does not have an impact greater than the 5% threshold. R2.2: Midwest ISO continues to believe that the text of this requirement is not clear. Midwest ISO asks the drafting team to consider the following language. At a minimum, establish the list of internal flowgates to create, modify, or delete at least once per calendar year. R2.3: Midwest ISO continues to believe that the text of this requirement is not clear. Midwest ISO asks the drafting team to consider the following language. At a minimum, establish the list of external flowgates to create, modify, or delete that have been requested as part of R2.1.4 within thirty calendar days from the request. R2.4: Both sub bullets instruct the entity to use the SOL for the flowgate. If this were to be the case, then R2.4 could be revised to just require the use of the SOL of the flowgate. Otherwise, the requirement should be revised to precisely capture the intention of the SDT. R5.3: How can this requirement be enforceable for entities that are non-FERC jurisdictional? We are concerned of the situation where a non-FERC jurisdictional neighboring entity doesn't provide such data to the Midwest ISO. We request clarification. R6.2/R6.4/R6.6/R7.2/R7.4/R7.6: Midwest ISO is not convinced that similar seams coordination requirements exist for the other two standards, especially for MOD-029. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies. We request to remove these requirements from MOD-030 to achieve |

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| | | | more unbiased standards. R11: Midwest ISO continues to question the language of this requirement for three reasons. First, the response from the SDT to our previous round of comments indicates that the TTC would remain constant because the flowgate with the lowest TFC would generally remain constant relative to each path. However, the SDT ignored the fact that the distribution factor for that same flowgate changes due to system topology changes. Hence, the TTC value will almost always change each time the model is updated, which is currently once per day as stated in R3. Second, the TTC value back calculated for the Flowgate methodology is not as valuable as it is in the Rated System Path methodology or the Area Interchange Methodology. If a flowgate will never limit an ATC, why would anyone be interested to know a TTC calculated by this flowgate? As the requirement is written, the Transmission Service Provider will be expected to incur additional cost, with no benefit to either the reliability or transmission customers, to separately account for the flowgate with the smallest TFC value in order to back calculate a TTC value. Third, when you use the same flowgate for all value conversions, the formula “ATC=TTC-CBMpath-TRMpath-ETCpath” still holds if you simply divide everything in formula “AFC=TFC-CBMflowgate-TRMflowgate-ETCflowgate” by the flowgate distribution factor. However, using different flowgates would make the formula “ATC=TTC-CBM-TRM-ETC” invalid. This result eliminates the usefulness of the TTC value for the Flowgate methodology. Therefore, we request this requirement to be rewritten if the SDT believes a formula to calculate TTC must be included in the standard. |
| Avista Corp. | 1 | Negative | The standard needs some flexibility due to regional differences. Support comments submitted by the Bonneville Power Administration. |
| Bonneville Power Administration | 1 | Negative | BPA believes this forces undue complication for our utility that could, in fact, lessen attention to reliability by adding extensive additional work without any gain in reliability. Our comments: 1. R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA’s part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of: load, generation, configuration of extensive special protection schemes (SPS), and WECC’s more stringent (greater than n-1) performance requirements determine which varying specific lines or equipment determine the capacity of the flowgate. While being made up of different named elements, BPA’s existing flowgates do not always include the first three limiting Elements and their worst associated Contingency combinations, yet they still protect the area of transmission constraint. An example of a basis for an ATC capacity that does not fit the proposed standard’s language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA’s North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for |

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| | | | (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows ("red/underlined" language indicates additions): R2.4. Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate. For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate. 2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between "(AFCs)" and "on"; R1, where a colon is missing following the "(ATCID)"; R2.1.2, where "analyses" should not be plural; and "R"s appear to be missing from all "fourth-tier" requirements (2.1.1.1 for example). |
| Brazos Electric Power Cooperative, Inc. | 1 | Negative | A NEGATIVE vote is cast for this standard as written as it imposes obligations on entities in the ERCOT region that do not utilize ATC paths and calculation methodologies to manage congestion or for reliability operations. Our previous submitted comments suggested that applicability language be included in the requirements to recognize that such market difference exists. |
| Central Lincoln PUD | 1 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the “Hub and Spoke” nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many |

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| | | | additional "flowgates" in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Public Power Council's members and other transmission customers will ultimately have to fund. Because the standard would unnecessarily impose these burdens without any incremental improvement in reliability, Central Lincoln PUD respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. Central Lincoln PUD supports Bonneville's proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |
| City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power | 1 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the "Hub and Spoke" nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional "flowgates" in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Tacoma Power and other transmission customers will ultimately have to fund. Because the standard would unnecessarily these burdens without any incremental improvement in reliability, Tacoma Power respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. Tacoma Power supports Bonneville's proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |
| Exelon Energy | 1 | Affirmative | General comment These standards bring the industry closer to a unified ATC calculation methodology by requiring that one of three calculation methodologies be utilized and documented. This is an improvement from where the industry is today but falls short of FERC Order No. 890. The standards still lack a requirement for ATC or AFC calculations to be consistent with criteria used in operating and planning studies for corresponding time periods. Exelon's comments reflect these deficiencies and |

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| | | | Exelon will be making these same points to FERC if these standards are approved, requesting that the FERC direct NERC to approve the standards but modify the standards to be consistent with Order No. 890. Suggested modifications to the standards to achieve this consistency are included in our comments. MOD-030-1 Flowgate Methodology Â· Requirement 2.1.1.1. and 2.1.2.1. need to be revised as follows:<br><br>Use first Contingency criteria consistent with those first Contingency used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems.<br><br>A requirement that the Available Transfer Capability Implementation Document specify the following: o PTDF and OTDF cutoff values used |
| FirstEnergy Energy Delivery | 1 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-030 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-030 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-030 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R2: Flowgate determination and calculation of TFC on flowgates. The variance would not be applicable to the TOP assignment in requirement R3, which requires the TOP to provide transmission modeling data to the TSP for the calculation of AFC. Additional Comments: In response to FE's most recent MOD-030 comments, the drafting team indicated that it felt the TOP is the appropriate entity for Requirement R2 since they are responsible for |

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| | | | keeping the system within its operating limits. While it is true that TOPs identify SOLs and are required to maintain SOLs, the use of flowgates is primarily a market function used in evaluating interchange transactions. Per FAC-014 requirement R5.2, TOPs are required to submit SOL information to TSPs and therefore the TSP would have the information available for the determination of Total Flow Capacity (TFC) for a given flowgate. Therefore, it is FE’s position that R2 is better assigned to the TSP, but if the SDT elects not to change the standard, the above request for a MISO variance will satisfy our needs. |
| Great River Energy | 1 | Negative | GRE is concerned with the Transmission Operator being the responsible entity for MOD-030_R2 and R3. GRE believes that the responsible entity for these requirements should be the Transmission Service Provider. It is GRE's opinion that a standard should not knowingly be written in a manner that requires delegation agreements to be created for a large number of responsible entities, doing so is an inefficient use of resources. |
| Manitoba Hydro | 1 | Negative | R2.1.3 - This requirement seems onerous. Having to calculate AFCs for a flowgate that was created for a temporary system configuration, once that system configuration has resolved, seems like work for little/no benefit. R2.2 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of internal flowgates to create, modify or delete at least once per calendar year. R2.3 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of external flowgates to create, modify or delete that have been requested as part of R2.1.4 within thirty calendar days from the request. R2.4 - It is unclear why the SDT differentiated between thermal and voltage/stability limits, when the instructions were to use the SOL regardless. R11 - Manitoba Hydro is not convinced that conversion from AFC to ATC can be easily calculated in a formula when different assumptions are used for calculating transmission capability. Manitoba Hydro also questions why is it only MOD 30 that requires a conversion formula? If standards are to be fair, shouldn't all three standards (MOD 28, MOD 29 and MOD 30) have as a requirement to convert transmission capability from one method to the other? Manitoba Hydro re-iterates that there shouldn't be 3 ways to calculate transmission capability. The standards should specify one methodology with consistent assumptions to preserve reliability. |
| PacifiCorp | 1 | Negative | PacifiCorp agrees with Bonneville Power's comments, listed below: 1. R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the Eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA’s part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new “flowgates” based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of: â€¢ Load â€¢ Generation â€¢ Configuration of extensive special protection schemes (SPS) and â€¢ WECC’s more stringent (greater than n-1) performance requirements determine which varying specific lines or equipment determine the capacity of the flowgate. While being made up of different named elements, BPA’s existing flowgates do not always include the first three limiting Elements and their worst associated contingency combinations, |

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| | | | yet they still protect the area of transmission constraint. An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows ("red/underlined" language indicates additions): R2.4. Establish the TFC of each of the defined Flowgates as equal to: â€“ For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate. â€“ For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate. |
| PP&L, Inc. | 1 | Negative | The R2.1.1 thru R2.1.2.2 requirements are inconsistent with western interconnection practices and may complicate the understanding of operational constraints which may negatively impact reliability. Therefore, PPL EU is in agreement with the comments posted by the Bonneville Power Administration, WECC and MISO and the recommendation to vote NO for this standard. |
| Seattle City Light | 1 | Abstain | The draft standard, in R2.1, proposes requirements for defining flowgates that appear to be inconsistent with approaches currently used in parts of the Western Interconnection to designate flowgate elements. The linear analysis method proposed will not sufficiently consider other System Operating Limits (SOLs) that may factor into flowgate designations. Specifically, the 5% Outage Transfer Distribution Factor (OTDF) threshold proposed for identifying flowgate elements does not reflect the methods currently used in WECC to designate flowgates. While application of OTDF methods is straight-forward, and provides a simple screening tool, it may be excessively burdensome to Transmission Operators to designate and redesignate flowgates using the proposed criteria. Furthermore, it may be impractical for Transmission Service Providers to manage requests for transmission services under pro forma OATT service provisions if the proposed criteria results in a large number of flowgates subject to simultaneous limits. SCL is in agreement with the apparent purpose of the R2.1 - establishing objective criteria with distinct metrics for flowgate designation. However, the |

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| | | | requirement R2.1 proposed in the draft should be replaced, perhaps using a WECC variance, to ensure that it results in a manageable number of flowgates that promote reliable operation of the Bulk Electric System. In standards FAC-010-1 and FAC-011-1 NERC has granted Regional Differences for establishing SOLs in the Western Interconnection. A similar Regional Difference should be developed and granted with respect to the establishment and designation of flowgates in the Western Interconnection. |
| Southwest Transmission Cooperative, Inc. | 1 | Abstain | SWTC does not use this methodology. |
| Western Area Power Administration | 1 | Negative | As written, complying with the standard would add substantial burden to "Flowgate" entities within the WECC while adding no additional reliability value. |
| California ISO | 2 | Negative | Implementation is incompatible with current operating practices in the Western Interconnection |
| Independent Electricity System Operator | 2 | Affirmative | R2.5 does not require a recalculation of TFC if the TOP becomes aware of a change to the transmission configuration such as an outage to a transmission facility. This should be required in addition to having to recalculating TFC upon being notified of a facility rating change. |
| Midwest ISO, Inc. | 2 | Abstain | R2.1.3: Midwest ISO believes that this requirement is too onerous and leaves no allowance for an Interconnection-wide congestion management process to be enacted due to a forced outage or any other system condition unforeseen by forecasted system conditions. Also, the SDT did not respond to Midwest ISO comment concerning temporary flowgates in TLR. Midwest ISO questions the reliability benefit gained by calculating AFCs for a flowgate which was only created for a temporary system condition. The response from the SDT to include limiting element/contingency combinations in R3.5 does not limit the potential list of flowgates to only adjacent Reliability Coordinator Areas as was originally intended. Language in R3.5 states “immediately adjacent and beyond Reliability Coordination Areas”, which implies the inclusion of Reliability Coordination Areas that are not adjacent. The Midwest ISO asks the SDT to clarify. Midwest ISO also believes that a flowgate referenced by R3.5 should be added by the process established in R2.1.4. Otherwise, as the requirement is written, if a forced outage causes an Interconnection-wide congestion management procedure to be enacted in on a limiting element/contingency in PJM, then Midwest ISO would be required to add that facility as a flowgate despite the opinion of PJM or even if a transfer from Midwest ISO to PJM does not have an impact greater than the 5% threshold. R2.2: Midwest ISO continues to believe that the text of this requirement is not clear. Midwest ISO asks the drafting team to consider the following language: R2.2: At a minimum, establish the list of internal flowgates to create, modify, or delete at least once per calendar year. R2.3: Midwest ISO continues to believe that the text of this requirement is not clear. Midwest ISO asks the drafting team to consider the following language: R2.3: At a minimum, establish the list of external flowgates to create, modify, or delete that have been requested as part of R2.1.4 within thirty calendar days from the request. R2.4: Both sub bullets instruct the entity to use the SOL for the flowgate. If this were to be the case, then R2.4 could be revised to just require the use of the SOL of the flowgate. Otherwise, the requirement should be revised to precisely capture the intention of |

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| | | | the SDT. R5.3: How can this requirement be enforceable for entities that are non-FERC jurisdictional? We are concerned of the situation where a non-FERC jurisdictional neighboring entity doesn't provide such data to the Midwest ISO. We request clarification. R6.2/R6.4/R6.6/R7.2/R7.4/R7.6 â€“ The Midwest ISO is not convinced that similar seams coordination requirements exist for the other two standards, especially for MOD-029. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies. We request to remove these requirements from MOD-030 to achieve more unbiased standards. R11: Midwest ISO continues to question the language of this requirement for three reasons. First, the response from the SDT to our previous round of comments indicates that the TTC would remain constant because the flowgate with the lowest TFC would generally remain constant relative to each path. However, the SDT ignored the fact that the distribution factor for that same flowgate changes due to system topology changes. Hence, the TTC value will almost always change each time the model is updated, which is currently once per day as stated in R3. Second, the TTC value back calculated for the Flowgate methodology is not as valuable as it is in the Rated System Path methodology or the Area Interchange Methodology. If a flowgate will never limit an ATC, why would anyone be interested to know a TTC calculated by this flowgate? As the requirement is written, the Transmission Service Provider will be expected to incur additional cost, with no benefit to either the reliability or transmission customers, to separately account for the flowgate with the smallest TFC value in order to back calculate a TTC value. Third, when you use the same flowgate for all value conversions, the formula "ATC=TTC-CBMpath-TRMpath-ETCpath"still holds if you simply divide everything in formula "AFC=TFC-CBMflowgate-TRMflowgate-ETCflowgate" by the flowgate distribution factor. However, using different flowgates would make the formula "ATC=TTC-CBM-TRM-ETC" invalid. This result eliminates the usefulness of the TTC value for the Flowgate methodology. Therefore, we request this requirement to be rewritten if the SDT believes a formula to calculate TTC must be included in the standard. The Midwest ISO acknowledges the fact that there can be three methodologies for calculating ATC values. The Midwest ISO continues to believe that a single standard that qualitatively judges the reliability of all three methodologies is the right form to ensure reliability of the interconnected bulk power systems rather than the current approach of having a separate standard for each methodology. The Midwest ISO believes that three different standards for three different methodologies have created requirements and measures to ensure that each entity is executing its methodology per the guidelines prescribed by the standards and do not necessarily ensure reliability of the interconnected system. For example, while the MOD-030 includes several requirements for Constraints (Flowgates) used in that methodology, the other standards do not include similar requirements with the premise that those methodologies do not use flowgates. For the system to be reliable, the constraints that impact an energy transfer should be the same irrespective of the methodology. The Midwest ISO sees these standards as guidelines to ensure documentation of the methodologies being executed as opposed to consistency amongst the methodologies to ensure system reliability. Midwest ISO also believes that the Flow based methodology is an advanced technique with a high level of detail and alignment with congestion management procedures such as the NERC IDC. The Midwest ISO continues to observe a significantly higher number of compliance |

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| | | | requirements under MOD-030 than entities using a methodology that is subject to either MOD-028 or MOD-029. The Midwest ISO believes that a single ATC standard and the termination of the three previously mentioned standards would eliminate any compliance concerns related to improperly aligned standards. Flow based methodology entities under MOD 030 are held to a higher degree of compliance for volunteering to use the Flow based methodology; when regardless of methodology the highest degree of compliance must required for all three methodologies. Therefore, the Midwest ISO believes it is imperative to draft a single ATC standard that would apply to all entities regardless of the methodology selected. |
| Ameren Services Company | 3 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-030-1. AFC is a market parameter and as such is applicable to the Transmission Service Provider. Definition of an adequate flowgate population is required to adequately constrain the sale of transmission service, as such this would appear to be a market not a reliability issue. Under R2 the calculation of TFC is applicable to the Transmission Operator. This is not consistent with the current version of the Functional Model. The Transmission Planner is responsible for supporting the development of TTC (TFC). Under R3 the Transmission Service Provider not the Transmission Operator should be responsible for the calculation of ATC/AFC and any modeling data. This is especially true when the Transmission Service Provider determines ATC for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO. That said we are aware that the oversubscription of transmission service can lead to reliability problems. AFC issues affect long term planning as well as planning in the Operating Time Horizon. |
| Avista Corp. | 3 | Negative | The standard needs some flexibility due to regional differences. Support comments submitted by the Bonneville Power Administration. |
| Blachly-Lane Electric Co-op | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| Bonneville Power Administration | 3 | Negative | 1. R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA's part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of: load, generation, configuration of extensive special protection schemes (SPS), and WECC's more stringent (greater than n-1) performance requirements determine which varying specific lines or equipment determine the capacity of the flowgate. While being made up of different named elements, BPA's existing flowgates do not always include the first three limiting Elements and their worst associated Contingency combinations, yet they still protect the area of transmission constraint. An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two |

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| | | | Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows: R2.4. Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate. For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate. 2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between "(AFCs)" and "on"; R1, where a colon is missing following the "(ATCID)"; R2.1.2, where "analyses" should not be plural; and "R"s appear to be missing from all "fourth-tier" requirements (2.1.1.1 for example). |
| City of McMinnville | 3 | Negative | Inappropriate methodology for WECC specific entities |
| City Public Service of San Antonio | 3 | Negative | I cannot vote for this standard as written. It needs to acknowledge definitive alternatives to ATC for regions or markets such as ERCOT where transmission service markets are not used. |
| Clatskanie People's Utility District | 3 | Negative | The requirement of substantial additional flowgate analysis does not add reliability and instead offers the possibility of a lower standard of understanding of system operation. |
| Clearwater Power Co. | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| Coos-Curry Electric Cooperative, Inc | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| Cowlitz County PUD | 3 | Negative | Cowlitz County PUD No.1 (District) Comments on MOD-030-1 Adapted from PPC Recommendations 7/29/08 The Northwest uses a flow-based ATC determination consistent with the main concepts of the |

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| | | | proposed MOD-030 standard. However, Northwest flowgates are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition, these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology is specifically designed to the “Hub and Spoke” nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. The District disagrees with current language in R2.1.1 and R2.1.2 of MOD-030 which will require the creation of many additional “flowgates” in the Northwest with no added reliability benefits. The current proven methodology used by the Bonneville Power Administration is sufficient. Adopting R2.1.1 and R2.1.2 of MOD-030 as it now stands will unnecessarily increase workload and cost. The District is not willing to help fund complicated reliability measures where there is no benefit. The District respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current methodology used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. The District supports Bonneville’s proposed changes to R2.1 of this proposed standard. |
| Duke Energy Carolina | 3 | Affirmative | While we support approval of this standard, bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on TTC/AFC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders. |
| FirstEnergy Solutions | 3 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-030 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-030 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO |

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| | | | Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-030 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R2: Flowgate determination and calculation of TFC on flowgates. The variance would not be applicable to the TOP assignment in requirement R3, which requires the TOP to provide transmission modeling data to the TSP for the calculation of AFC. Additional Comments: In response to FE's most recent MOD-030 comments, the drafting team indicated that it felt the TOP is the appropriate entity for Requirement R2 since they are responsible for keeping the system within its operating limits. While it is true that TOPs identify SOLs and are required to maintain SOLs, the use of flowgates is primarily a market function used in evaluating interchange transactions. Per FAC-014 requirement R5.2, TOPs are required to submit SOL information to TSPs and therefore the TSP would have the information available for the determination of Total Flow Capacity (TFC) for a given flowgate. Therefore, it is FE's position that R2 is better assigned to the TSP, but if the SDT elects not to change the standard, the above request for a MISO variance will satisfy our needs. |
| Lost River Electric Cooperative | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| Manitoba Hydro | 3 | Negative | R2.1.3 - This requirement seems onerous. Having to calculate AFCs for a flowgate that was created for a temporary system configuration, once that system configuration has resolved, seems like work for little/no benefit. R2.2 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of internal flowgates to create, modify or delete at least once per calendar year. R2.3 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of external flowgates to create, modify or delete that have been requested as part of R2.1.4 within thirty calendar days from the request. R2.4 - It is unclear why the SDT differentiated between thermal and voltage/stability limits, when the instructions were to use the SOL regardless. R11 - Manitoba Hydro is not convinced that conversion from AFC to ATC can be easily calculated in a formula when different assumptions are used for calculating transmission capability. Manitoba Hydro also questions why is it only MOD 30 that requires a conversion formula? If standards are to be fair, shouldn't all three standards (MOD 28, MOD 29 and MOD 30) have as a requirement to convert transmission capability from one method to the other? Manitoba Hydro re-iterates that there shouldn't be 3 ways to calculate transmission capability. The standards should specify one methodology with consistent assumptions to preserve reliability. |
| **Response:** | | | |

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| MidAmerican Energy Co. | 3 | Negative | I am concerned that R2.1 requires the Transmission Operator to set up a certain number of flowgates at a minimum. With smaller Transmission Service Providers, I believe this will result unnecessarily in additional flow gates in the interconnection. I believe R2.1. should be greatly simplified, deleted, or else changes should be made to R2.1.3. Add at the end of R2.1.3 an exclusion from the requirement of adding flowgates for situations that resulted in congestion management "unless the need for Interconnection-wide congestion management was a result of unusual operating conditions that are not reasonably expected to frequently occur again (such as multiple prior outages of transmission facilities and/or critical generators)." |
| Northern Lights Inc. | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| Northern Wasco County People's Utility District (PUD) | 3 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the “Hub and Spoke” nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional “flowgates” in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Northern Wasco County PUD and other transmission customers will ultimately have to fund. Because the standard would unnecessarily impose these burdens without any incremental improvement in reliability, Northern Wasco County PUD respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. Northern Wasco County PUD supports Bonneville’s proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |
| Okanogan County Electric Cooperative, Inc. | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| Public Utility | 3 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed |

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| District No. 1 of Benton County | | | MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the “Hub and Spoke” nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional “flowgates” in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Public Utility District No. 1 of Benton County (Benton PUD) and other transmission customers will ultimately have to fund. Because the standard would unnecessarily impose these burdens without any incremental improvement in reliability, Benton PUD respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. Benton PUD supports Bonneville’s proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |
| Public Utility District No. 2 of Grant County | 3 | Negative | The additional requirements add no reliability to the system in the western interconnection. |
| Raft River Rural Electric Cooperative | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| Salmon River Electric Cooperative | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| Seattle City Light | 3 | Abstain | The draft standard, in R2.1, proposes requirements for defining flowgates that appear to be inconsistent with approaches currently used in parts of the Western Interconnection to designate flowgate elements. The linear analysis method proposed will not sufficiently consider other System Operating Limits (SOLs) that may factor into flowgate designations. Specifically, the 5% Outage Transfer Distribution Factor (OTDF) threshold proposed for identifying flowgate elements does not reflect the methods currently used in WECC to designate flowgates. While application of OTDF |

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| | | | methods is straight-forward, and provides a simple screening tool, it may be excessively burdensome to Transmission Operators to designate and redesignate flowgates using the proposed criteria. Furthermore, it may be impractical for Transmission Service Providers to manage requests for transmission services under pro forma OATT service provisions if the proposed criteria results in a large number of flowgates subject to simultaneous limits. SCL is in agreement with the apparent purpose of the R2.1 - establishing objective criteria with distinct metrics for flowgate designation. However, the requirement R2.1 proposed in the draft should be replaced, perhaps using a WECC variance, to ensure that it results in a manageable number of flowgates that promote reliable operation of the Bulk Electric System. In standards FAC-010-1 and FAC-011-1 NERC has granted Regional Differences for establishing SOLs in the Western Interconnection. A similar Regional Difference should be developed and granted with respect to the establishment and designation of flowgates in the Western Interconnection. |
| Umatilla Electric Cooperative | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| Wisconsin Public Service Corp. | 3 | Negative | R2 needs to be simplified. |
| Alliant Energy Corp. Services, Inc. | 4 | Negative | We believe that R2.1 requires the Transmission Operator to set up a certain number of flowgates. We believe this will require that many flowgates will be needlessly set up. |
| Eugene Water & Electric Board | 4 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the “Hub and Spoke” nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional “flowgates” in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Eugene Water & Electric Board (EWEB) and other transmission customers will ultimately have to fund. Because the standard would unnecessarily these burdens without any incremental improvement in reliability, EWEB respectfully requests that alternate WECC-specific requirements be added to replace |

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| | | | R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. EWEB supports Bonnevilleâ€™s proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |
| Pacific Northwest Generating Cooperative | 4 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| Public Power Council | 4 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the “Hub and Spoke” nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional “flowgates” in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Public Power Council’s members and other transmission customers will ultimately have to fund. Because the standard would unnecessarily impose these burdens without any incremental improvement in reliability, Public Power Council respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. Public Power Council supports Bonneville’s proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |
| Public Utility District No. 1 of Douglas County | 4 | Negative | We have not had sufficient time to adequately review and coordinate the issue within our region. |
| Public Utility District No. 1 of Snohomish County | 4 | Negative | The District Intends To Vote As Follows: MOD-001: votes Abstain, with no comments MOD-030 comments: The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. However northwest flowgates are defined to provide adequate granularity needed to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying |

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| | | | temperatures/loads/rating, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider/operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the “Hub and Spoke” nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional “flowgates” in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 would unnecessarily introduce significant workload, cost, and complications that the District and other transmission customers will ultimately have to fund. For these reasons, the District believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The District supports the Bonneville Power Administration proposed “WECC-specific” language to address the hybrid AFC-contract-path calculation used in the Northwest. This hybrid method is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. |
| Seattle City Light | 4 | Abstain | The draft standard, in R2.1, proposes requirements for defining flowgates that appear to be inconsistent with approaches currently used in parts of the Western Interconnection to designate flowgate elements. The linear analysis method proposed will not sufficiently consider other System Operating Limits (SOLs) that may factor into flowgate designations. Specifically, the 5% Outage Transfer Distribution Factor (OTDF) threshold proposed for identifying flowgate elements does not reflect the methods currently used in WECC to designate flowgates. While application of OTDF methods is straight-forward, and provides a simple screening tool, it may be excessively burdensome to Transmission Operators to designate and redesignate flowgates using the proposed criteria. Furthermore, it may be impractical for Transmission Service Providers to manage requests for transmission services under pro forma OATT service provisions if the proposed criteria results in a large number of flowgates subject to simultaneous limits. SCL is in agreement with the apparent purpose of the R2.1 - establishing objective criteria with distinct metrics for flowgate designation. However, the requirement R2.1 proposed in the draft should be replaced, perhaps using a WECC variance, to ensure that it results in a manageable number of flowgates that promote reliable operation of the Bulk Electric System. In standards FAC-010-1 and FAC-011-1 NERC has granted Regional Differences for establishing SOLs in the Western Interconnection. A similar Regional Difference should be developed and granted with respect to the establishment and designation of flowgates in the Western Interconnection. |
| WPS Resources | 4 | Negative | R2.1 requires that the Transmission Operator shall set up a certain number of flowgates at a minimum. |

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| Corp. | | | This could result in a certain flowgates that are not needed on an on-going basis. This requirement should be simplified, deleted, and/or changed. R2.1.3. presently states that "Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology." This requirement should provide another condition when the requirement is waived by adding the following words at the end of the requirement "or unless the need for Interconnection-wide congestion management was a result of unusual operating conditions that are not reasonably expected to frequently occur again (such as multiple prior outages of transmission facilities and/or critical generators)." Also, the Transmission Operator is the responsible entity for R2 through R3 for MOD-030. The responsible entity for these requirements should be the Transmission Service Provider. |
| Avista Corp. | 5 | Negative | This standard needs to incorporate the need for regional differences. We support the comments submitted by BPA. |
| Bonneville Power Administration | 5 | Negative | 1. R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the eastern interconnection. However, existing practices in BPA's part of the western interconnection use flow based ATC determination which, while consistent with the concepts of this proposed standard, use a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability - where the specific characteristics of load, generation, configuration of extensive special protection schemes (SPS), and WECC's more stringent (greater than n-1) performance requirements - to determine which varying specific lines or equipment determine the capacity of the flowgate. While made up of different named elements, BPA's existing flowgates do not always include the first three limiting elements and their worst associated Contingency combinations, yet they still protect the area of transmission constraint. An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC- |

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| | | | specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows ("red/underlined" language indicates additions): R2.4. Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate. For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate. 2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between "(AFCs)" and "on"; R1, where a colon is missing following the "(ATCID)"; R2.1.2, where "analyses" should not be plural; and "R"s appear to be missing from all "fourth-tier" requirements (2.1.1.1 for example). |
| FirstEnergy Solutions | 5 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-030 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-030 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-030 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R2: Flowgate determination and calculation of TFC on flowgates. The variance would not be applicable to the TOP assignment in requirement R3, which requires the TOP to provide transmission modeling data to the TSP for the calculation of AFC. Additional Comments: In response to FE's most recent MOD-030 comments, the drafting team |

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| | | | indicated that it felt the TOP is the appropriate entity for Requirement R2 since they are responsible for keeping the system within its operating limits. While it is true that TOPs identify SOLs and are required to maintain SOLs, the use of flowgates is primarily a market function used in evaluating interchange transactions. Per FAC-014 requirement R5.2, TOPs are required to submit SOL information to TSPs and therefore the TSP would have the information available for the determination of Total Flow Capacity (TFC) for a given flowgate. Therefore, it is FE's position that R2 is better assigned to the TSP, but if the SDT elects not to change the standard, the above request for a MISO variance will satisfy our needs. |
| IBERDROLA RENEWABLES | 5 | Negative | R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the Eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA's part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of:<br><br>– Load<br>– Generation<br>– Configuration of extensive special protection schemes (SPS) and<br>– WECC's more stringent (greater than n-1) performance requirements determine which varying specific lines or equipment determine the capacity of the flowgate.<br><br>While being made up of different named elements, BPA's existing flowgates do not always include the first three limiting Elements and their worst associated contingency combinations, yet they still protect the area of transmission constraint. An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC- |

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| | | | specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows ("red/underlined" language indicates additions): R2.4. Establish the TFC of each of the defined Flowgates as equal to:<br><br>– For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate.<br>– For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate. 2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between"(AFCs)" and "on"; R1, where a colon is missing following the "(ATCID)"; R2.1.2, where "analyse" should not be plural; and "R"s appear to be missing from all "fourth-tier" requirements (2.1.1.1 for example). |
| Manitoba Hydro | 5 | Negative | R2.1.3 - This requirement seems onerous. Having to calculate AFCs for a flowgate that was created for a temporary system configuration, once that system configuration has resolved, seems like work for little/no benefit. R2.2 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of internal flowgates to create, modify or delete at least once per calendar year. R2.3 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of external flowgates to create, modify or delete that have been requested as part of R2.1.4 within thirty calendar days from the request. R2.4 - It is unclear why the SDT differentiated between thermal and voltage/stability limits, when the instructions were to use the SOL regardless. R11 - Manitoba Hydro is not convinced that conversion from AFC to ATC can be easily calculated in a formula when different assumption are used for calculating transmission capability. Manitoba Hydro also questions why is it only MOD 30 that requires a conversion formula? If standards are to be fair, shouldn't all three standards (MOD 28, MOD 29 and MOD 30) have as a requirement to convert transmission capability from one method to the other? Manitoba Hydro re-iterates that there shouldn't be 3 ways to calculate transmission capability. The standards should specify one methodology with consistent assumptions to preserve reliability. |
| PPL Generation LLC | 5 | Negative | We are respecting BPA's and MISO's position on this ballot in our decision to vote negative. |
| Bonneville Power Administration | 6 | Negative | 1. R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA's part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria |

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| FirstEnergy Solutions | 6 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-030 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, |

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| | | | in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-030 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-030 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R2: Flowgate determination and calculation of TFC on flowgates. The variance would not be applicable to the TOP assignment in requirement R3, which requires the TOP to provide transmission modeling data to the TSP for the calculation of AFC. Additional Comments: In response to FE's most recent MOD-030 comments, the drafting team indicated that it felt the TOP is the appropriate entity for Requirement R2 since they are responsible for keeping the system within its operating limits. While it is true that TOPs identify SOLs and are required to maintain SOLs, the use of flowgates is primarily a market function used in evaluating interchange transactions. Per FAC-014 requirement R5.2, TOPs are required to submit SOL information to TSPs and therefore the TSP would have the information available for the determination of Total Flow Capacity (TFC) for a given flowgate. Therefore, it is FE's position that R2 is better assigned to the TSP, but if the SDT elects not to change the standard, the above request for a MISO variance will satisfy our needs. |
| IBERDROLA RENEWABLES | 6 | Negative | R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the Eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA's part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of:<br><br>– Load – Generation<br>– Configuration of extensive special protection schemes (SPS) and<br>– WECC's more stringent (greater than n-1) performance requirements determine which varying |

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| | | | specific lines or equipment determine the capacity of the flowgate. While being made up of different named elements, BPA's existing flowgates do not always include the first three limiting Elements and their worst associated contingency combinations, yet they still protect the area of transmission constraint.<br>An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are added, to replace R2.1.1- 2.1.2.2 for WECC entities, R2.4 would also require modification as follows ("red/underline" language indicates additions): R2.4. Establish the TFC of each of the defined Flowgates as equal to:<br>For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate. For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate. 2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between "(AFCs)" and "on"; R1, where a colon is missing following the "(ATCID)'; R2.1.2, where "analyses" should not be plural; and "R" appear to be missing from all "fourth-tier" requirements (2.1.1.1 for example). |
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| | | | formula when different assumptions are used for calculating transmission capability. Manitoba Hydro also questions why is it only MOD 30 that requires a conversion formula? If standards are to be fair, shouldn't all three standards (MOD 28, MOD 29 and MOD 30) have as a requirement to convert transmission capability from one method to the other? Manitoba Hydro re-iterates that there shouldn't be 3 ways to calculate transmission capability. The standards should specify one methodology with consistent assumptions to preserve reliability. |
| Public Utility District No. 1 of Chelan County | 6 | Negative | Standard as written complicates transmission service from the Bonneville Power Authority without adding reliability. |
| Electric Reliability Council of Texas, Inc. | 10 | Abstain | Although stated in the Applicability Section, the Requirements and Measures contain no clear applicability only to those Transmission Operators and Transmission Service providers who utilize the Flowgate methodology in calculating Available Flowgate Capabilities. |
| Midwest Reliability Organization | 10 | Negative | The MRO is concerned with the R2.1 that requires that the Transmission Operator shall set up a certain number of flowgates at a minimum. The MRO is concerned that this will require a certain number of flowgates will be needlessly set up by smaller Transmission Service Providers as a result of this requirement. The MRO believes that this will result in a certain number of flowgates be needlessly set up. We believe that this requirement should be greatly simplified, deleted, and/or changes to R2.1.3 should be made. R2.1.3. presently states that "Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology." We believe that this requirement should provide another condition when the requirement is waived by adding the following words at the end of the requirement "or unless the need for Interconnection-wide congestion management was a result of unusual operating conditions that are not reasonably expected to frequently occur again (such as multiple prior outages of transmission facilities and/or critical generators)." Also, the MRO is concerned with the Transmission Operator being the responsible entity for R2 through R3 for MOD-030. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |

## Consideration of Comments on Initial Ballot — MOD-030-1 — Flowgate Methodology

**Summary Consideration:** Some stakeholders identified typographical errors in the standard, and these have been corrected as noted below. The announcement for the recirculation ballot will include a notice of these corrections.

- Applicability 4.1.1, - added a space between "(AFCs)" and "on"
- R1 - replaced the "period" with a "colon" following "(ATCID)"
- R2.1.2 - changed "analyses" to "analysis"
- Added "R"s to all "fourth-tier" requirements (changing 2.1.1.1 to R2.1.1.1 for example)

While some stakeholders suggested modifications to the standard, the Drafting Team has decided to address these changes in the next version of the standard, which is currently under development and will be posted for comment at the same time as the recirculation ballot. The drafting team did not make any changes, other than correcting typographical errors, to the standard.

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| Ameren Services Company | 1 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-030-1.<br>(1) AFC is a market parameter and as such is applicable to the Transmission Service Provider.<br>(2) Definition of an adequate flowgate population is required to adequately constrain the sale of transmission service, as such this would appear to be a market not a reliability issue.<br>(3) Under R2 the calculation of TFC is applicable to the Transmission Operator. This is not consistent with the current version of the Functional Model. The Transmission Planner is responsible for supporting the development of TTC (TFC).<br>(3) Under R3 the Transmission Service Provider not the Transmission Operator should be responsible for the calculation of ATC/AFC and any modeling data. This is especially true when the Transmission Service Provider determines ATC for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO.<br>(4) That said we are aware that the oversubscription of transmission service can lead to reliability problems.<br>(5)AFC issues affect long term planning as well as planning in the Operating Time Horizon. |
| **Response:** The SDT has assigned the portions of the flowgate methodology related to AFC to the Transmission Service Provider.<br><br>The SDT believes the determination of flowgate is a reliability consideration, and defines how the transmission system is to be analyzed for reliability reasons with regard to determining the impacts of forecast usage of that system. | | | |

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| The Functional Model does not attribute the determination of TTC or TFC to any entity. As such, the SDT was required to interpret the model to determine the appropriate entity for determining TTC or TFC. Since the ratings of facilities are established by the Transmission Operator, the SDT felt it appropriate to assign the responsibility for TFC to the Transmission Operator.<br><br>Under R3, the Transmission Operator is not responsible for calculating AFC – only providing the Transmission Service Provider with a model to use in that calculation. While many entities may have delegated this task to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. NERC has attempted to address this through allowing the use of Joint Registration Organizations, where a MISO/Ameren collaboration would be sanctioned as a single entity, and then the JRO would be responsible for determining how to allocate those sanctions among participants in the JRO.<br><br>The SDT concurs that oversubscription can lead to reliability problems.<br><br>With regard to the Time Horizons used in compliance, the SDT believes the correct horizon is Operations Planning. | | | |
| American Transmission Company, LLC | 1 | Negative | R2.1.3: Midwest ISO believes that this requirement is too onerous and leaves no allowance for an Interconnection-wide congestion management process to be enacted due to a forced outage or any other system condition unforeseen by forecasted system conditions. Also, the SDT did not respond to Midwest ISO comment concerning temporary flowgates in TLR. Midwest ISO questions the reliability benefit gained by calculating AFCs for a flowgate which was only created for a temporary system condition. Midwest ISO also believes that a flowgate referenced by R3.5 should be added by process established in R2.1.4. Otherwise, as the requirement is written, if a forced outage causes an Interconnection-wide congestion management procedure to be enacted in on a limiting element/contingency in PJM, then Midwest ISO would be required to add that facility as a flowgate despite the opinion of PJM or even if a transfer from Midwest ISO to PJM does not have an impact greater than the 5% threshold.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.2: Midwest ISO continues to believe that the text of this requirement is not clear. Midwest ISO asks the drafting team to consider the following language. At a minimum, establish the list of internal flowgates to create, modify, or delete at least once per calendar year. |

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| | | | **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.3: Midwest ISO continues to believe that the text of this requirement is not clear. Midwest ISO asks the drafting team to consider the following language. At a minimum, establish the list of external flowgates to create, modify, or delete that have been requested as part of R2.1.4 within thirty calendar days from the request.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.4: Both sub bullets instruct the entity to use the SOL for the flowgate. If this were to be the case, then R2.4 could be revised to just require the use of the SOL of the flowgate. Otherwise, the requirement should be revised to precisely capture the intention of the SDT.<br>**Response:** The first bullet requires that for SOLs with a limit based on megawatts, that the megawatt value be used. However, for SOLs with limits based on MVARs or other units, the flowgate limit would need to be specified as a level of flow in megawatts that supports the SOL. This is the intent of bullet two.<br><br>R5.3: How can this requirement be enforceable for entities that are non-FERC jurisdictional? We are concerned of the situation where a non-FERC jurisdictional neighboring entity doesn't provide such data to the Midwest ISO. We request clarification.<br>**Response:** Entities are only required to use AFCs they have been provided; if the information has not been provided, entities are not expected to use it. All entities within the continental United States are subject to mandatory and enforceable standards developed by the ERO. Entities outside the United States may be responsible for providing this information based on the regulatory agencies under which they operate. |

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| | | | R6.2/R6.4/R6.6/R7.2/R7.4/R7.6: Midwest ISO is not convinced that similar seams coordination requirements exist for the other two standards, especially for MOD-029. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies. We request to remove these requirements from MOD-030 to achieve more unbiased standards.<br>**Response:** MOD-029 is not a simulation-based methodology. As such, it is inappropriate to require the same kind of coordination as is described in MOD-028 and MOD-030. The SDT reiterates that MOD-028 does require similar coordination in R3 (generation dispatch and load for neighboring areas) and R4.3 (firm reservations from neighboring areas).<br><br>R11: Midwest ISO continues to question the language of this requirement for three reasons.<br>First, the response from the SDT to our previous round of comments indicates that the TTC would remain constant because the flowgate with the lowest TFC would generally remain constant relative to each path. However, the SDT ignored the fact that the distribution factor for that same flowgate changes due to system topology changes. Hence, the TTC value will almost always change each time the model is updated, which is currently once per day as stated in R3.<br>Second, the TTC value back calculated for the Flowgate methodology is not as valuable as it is in the Rated System Path methodology or the Area Interchange Methodology. If a flowgate will never limit an ATC, why would anyone be interested to know a TTC calculated by this flowgate? As the requirement is written, the Transmission Service Provider will be expected to incur additional cost, with no benefit to either the reliability or transmission customers, to separately account for the flowgate with the smallest TFC value in order to back calculate a TTC value.<br>Third, when you use the same flowgate for all value conversions, the formula “ATC=TTC-CBMpath-TRMpath-ETCpath” still holds if you simply divide everything in formula “AFC=TFC-CBMflowgate-TRMflowgate-ETCflowgate” by the flowgate distribution factor. However, using different flowgates would make the formula “ATC=TTC-CBM-TRM-ETC” invalid. This result eliminates the usefulness of the TTC value for the Flowgate methodology. Therefore, we request this requirement to be rewritten if the SDT believes a formula to calculate TTC must be included in the standard.<br>**Response:** The SDT recognizes the commenter’s concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision |

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| | | | for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. |
| **Response:** Please see in-line responses. | | | |
| Avista Corp. | 1 | Negative | The standard needs some flexibility due to regional differences. Support comments submitted by the Bonneville Power Administration. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address concerns raised by BPA (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Bonneville Power Administration | 1 | Negative | BPA believes this forces undue complication for our utility that could, in fact, lessen attention to reliability by adding extensive additional work without any gain in reliability. Our comments:<br><br>1. R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA's part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions.<br><br>MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of: load, generation, configuration of extensive special protection schemes (SPS), and WECC's more stringent (greater than n-1) performance requirements determine which varying specific lines or equipment determine the capacity of the flowgate.<br><br>While being made up of different named elements, BPA's existing flowgates do not always include the first three limiting Elements and their worst associated Contingency combinations, yet they still protect the area of transmission constraint.<br>An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a |

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| | | | limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate.<br><br>In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference:<br><br>RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability.<br>RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate.<br><br>If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows ("red/underlined" language indicates additions):<br>R2.4. Establish the TFC of each of the defined Flowgates as equal to:<br>For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate.<br>For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate.<br><br>2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between "(AFCs)" and "on"; R1, where a colon is missing following the "(ATCID)"; R2.1.2, where "analyses" should not be plural; and "R"s appear to be missing from all "fourth-tier" requirements (2.1.1.1 for example). |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>The typographical errors have been corrected and an updated version of the standard has been posted for stakeholders to see – these corrections will be noted in the announcement for the recirculation ballot. | | | |

<table>
<tr><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Brazos Electric Power Cooperative, Inc.</td><td>1</td><td>Negative</td><td>A NEGATIVE vote is cast for this standard as written as it imposes obligations on entities in the ERCOT region that do not utilize ATC paths and calculation methodologies to manage congestion or for reliability operations. Our previous submitted comments suggested that applicability language be included in the requirements to recognize that such market difference exists.</td></tr>
<tr><td colspan="4">Response: If ERCOT does not choose to implement this methodology, then this standard would not apply to ERCOT. If ERCOT does not have ATC Paths, or ERCOT has an associated variance, MOD-001 would not require them to select a methodology.</td></tr>
<tr><td>Central Lincoln PUD</td><td>1</td><td>Negative</td><td>The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the “Hub and Spoke” nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional “flowgates” in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Public Power Council’s members and other transmission customers will ultimately have to fund. Because the standard would unnecessarily impose these burdens without any incremental improvement in reliability, Central Lincoln PUD respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. Central Lincoln PUD supports Bonneville’s proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard.</td></tr>
<tr><td colspan="4">Response: The SDT recognizes the commenter’s concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-</td></tr>
</table>

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| 030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power | 1 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the “Hub and Spoke” nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional “flowgates” in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Tacoma Power and other transmission customers will ultimately have to fund. Because the standard would unnecessarily these burdens without any incremental improvement in reliability, Tacoma Power respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. Tacoma Power supports Bonneville’s proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |
| **Response:** The SDT recognizes the commenter’s concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Exelon Energy | 1 | Affirmative | General comment These standards bring the industry closer to a unified ATC calculation methodology by requiring that one of three calculation methodologies be utilized and documented. This is an improvement from where the industry is today but falls short of FERC Order No. 890. The standards still lack a requirement for ATC or AFC calculations to be consistent with criteria used in operating and planning studies |

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| | | | for corresponding time periods. Exelon's comments reflect these deficiencies and Exelon will be making these same points to FERC if these standards are approved, requesting that the FERC direct NERC to approve the standards but modify the standards to be consistent with Order No. 890. Suggested modifications to the standards to achieve this consistency are included in our comments. MOD-030-1 Flowgate Methodology Â· Requirement 2.1.1.1. and 2.1.2.1. need to be revised as follows:<br><br>Use first Contingency criteria consistent with those first Contingency used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems.<br><br>A requirement that the Available Transfer Capability Implementation Document specify the following: o PTDF and OTDF cutoff values used |
| **Response:** The SDT notes MOD-001 R6 and R7 are intended to address the contingency concerns described in Exelon's comments, as well as R2.1.2.1 of MOD-030. The SDT notes that the "planning of operations" language has intentionally been taken directly from Order 890 to ensure consistency with the Commission's intent.<br><br>The SDT notes that MOD-001 R3.1 already indirectly requires the PTDF and OTDF information suggested. | | | |
| FirstEnergy Energy Delivery | 1 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-030 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written.<br>In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-030 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC |

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| | | | standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-030 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R2: Flowgate determination and calculation of TFC on flowgates. The variance would not be applicable to the TOP assignment in requirement R3, which requires the TOP to provide transmission modeling data to the TSP for the calculation of AFC.<br>Additional Comments: In response to FE's most recent MOD-030 comments, the drafting team indicated that it felt the TOP is the appropriate entity for Requirement R2 since they are responsible for keeping the system within its operating limits. While it is true that TOPs identify SOLs and are required to maintain SOLs, the use of flowgates is primarily a market function used in evaluating interchange transactions. Per FAC-014 requirement R5.2, TOPs are required to submit SOL information to TSPs and therefore the TSP would have the information available for the determination of Total Flow Capacity (TFC) for a given flowgate. Therefore, it is FE's position that R2 is better assigned to the TSP, but if the SDT elects not to change the standard, the above request for a MISO variance will satisfy our needs. |
| **Response**: The SDT believes that the assignment to the Transmission Operator is correct. However, if MISO or its members wish to pursue an entity variance, they may submit a SAR requesting such a variance as defined in the NERC Reliability Standards Development Procedure. | | | |
| Great River Energy | 1 | Negative | GRE is concerned with the Transmission Operator being the responsible entity for MOD-030_R2 and R3. GRE believes that the responsible entity for these requirements should be the Transmission Service Provider. It is GRE's opinion that a standard should not knowingly be written in a manner that requires delegation agreements to be created for a large number of responsible entities, doing so is an inefficient use of resources. |
| **Response:** The SDT acknowledges that some entities stated that their Transmission Service Provider performed the tasks associated with R2 and R3, and that it may be easier for a regional entity to perform these tasks, but no entity has provided support (through the Functional Model or any other means) for why the responsibility should be shifted to the Transmission Service Provider. The SDT also notes that in previous comments, some entities supported the assignment to the Transmission Operator. | | | |
| Manitoba Hydro | 1 | Negative | R2.1.3 - This requirement seems onerous. Having to calculate AFCs for a flowgate that was created for a temporary system configuration, once that system configuration has resolved, seems like work for little/no benefit.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to |

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| | | | MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.2 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of internal flowgates to create, modify or delete at least once per calendar year.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.3 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of external flowgates to create, modify or delete that have been requested as part of R2.1.4 within thirty calendar days from the request.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.4 - It is unclear why the SDT differentiated between thermal and voltage/stability limits, when the instructions were to use the SOL regardless.<br>**Response:** The first bullet requires that for SOLs with a limit based on megawatts, that the megawatt value be used. However, for SOLs with limits based on MVARs or other units, the flowgate limit would need to be specified as a level of flow in megawatts that supports the SOL. This is the intent of bullet two.<br><br>R11 - Manitoba Hydro is not convinced that conversion from AFC to ATC can be easily calculated in a formula when different assumptions are used for calculating transmission capability. Manitoba Hydro also questions why is it only MOD 30 that requires a conversion formula? If standards are to be fair, shouldn't all three standards (MOD 28, MOD 29 and MOD 30) have as a requirement to convert transmission |

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| | | | capability from one method to the other? Manitoba Hydro re-iterates that there shouldn't be 3 ways to calculate transmission capability. The standards should specify one methodology with consistent assumptions to preserve reliability.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. |
| **Response:** Please see in-line responses. | | | |
| PacifiCorp | 1 | Negative | PacifiCorp agrees with Bonneville Power's comments, listed below:<br>1. R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the Eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA's part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of: â€¢ Load â€¢ Generation â€¢ Configuration of extensive special protection schemes (SPS) and â€¢ WECC's more stringent (greater than n-1) performance requirements determine which varying specific lines or equipment determine the capacity of the flowgate. While being made up of different named elements, BPA's existing flowgates do not always include the first three limiting Elements and their worst associated contingency combinations, yet they still protect the area of transmission constraint. An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity |

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| | | | compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference:<br><br>RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability.<br><br>RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate.<br><br>If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows ("red/underlined" language indicates additions):<br>R2.4. Establish the TFC of each of the defined Flowgates as equal to: â€" For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate. â€" For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate. |
| **Response**: The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| PP&L, Inc. | 1 | Negative | The R2.1.1 thru R2.1.2.2 requirements are inconsistent with western interconnection practices and may complicate the understanding of operational constraints which may negatively impact reliability. Therefore, PPL EU is in agreement with the comments posted by the Bonneville Power Administration, WECC and MISO and the recommendation to vote NO for this standard. |
| **Response:** Please see responses to BPA, other WECC entities and MISO. | | | |
| Seattle City Light | 1 | Abstain | The draft standard, in R2.1, proposes requirements for defining flowgates that appear to be inconsistent with approaches currently used in parts of the Western Interconnection to designate flowgate elements. The linear analysis method proposed will not sufficiently consider other System Operating Limits (SOLs) that may factor into flowgate designations.<br>Specifically, the 5% Outage Transfer Distribution Factor (OTDF) threshold proposed for identifying flowgate elements does not reflect the methods currently used in WECC |

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| | | | to designate flowgates. While application of OTDF methods is straight-forward, and provides a simple screening tool, it may be excessively burdensome to Transmission Operators to designate and redesignate flowgates using the proposed criteria. Furthermore, it may be impractical for Transmission Service Providers to manage requests for transmission services under pro forma OATT service provisions if the proposed criteria results in a large number of flowgates subject to simultaneous limits. SCL is in agreement with the apparent purpose of the R2.1 - establishing objective criteria with distinct metrics for flowgate designation. However, the requirement R2.1 proposed in the draft should be replaced, perhaps using a WECC variance, to ensure that it results in a manageable number of flowgates that promote reliable operation of the Bulk Electric System. In standards FAC-010-1 and FAC-011-1 NERC has granted Regional Differences for establishing SOLs in the Western Interconnection. A similar Regional Difference should be developed and granted with respect to the establishment and designation of flowgates in the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Southwest Transmission Cooperative, Inc. | 1 | Abstain | SWTC does not use this methodology. |
| **Response:** Thank you for your comment. | | | |
| Western Area Power Administration | 1 | Negative | As written, complying with the standard would add substantial burden to "Flowgate" entities within the WECC while adding no additional reliability value. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| California ISO | 2 | Negative | Implementation is incompatible with current operating practices in the Western Interconnection |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Independent Electricity System Operator | 2 | Affirmative | R2.5 does not require a recalculation of TFC if the TOP becomes aware of a change to the transmission configuration such as an outage to a transmission facility. This should be required in addition to having to recalculating TFC upon being notified of a facility rating change. |

| Entity | Segment | Vote | Comment |
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| **Response:** The SDT believes that the modeling and outage requirements contained in R3 would result in an update to the AFC, which would reflect the changing conditions described. | | | |
| Midwest ISO, Inc. | 2 | Abstain | R2.1.3: Midwest ISO believes that this requirement is too onerous and leaves no allowance for an Interconnection-wide congestion management process to be enacted due to a forced outage or any other system condition unforeseen by forecasted system conditions. Also, the SDT did not respond to Midwest ISO comment concerning temporary flowgates in TLR. Midwest ISO questions the reliability benefit gained by calculating AFCs for a flowgate which was only created for a temporary system condition. Midwest ISO also believes that a flowgate referenced by R3.5 should be added by process established in R2.1.4. Otherwise, as the requirement is written, if a forced outage causes an Interconnection-wide congestion management procedure to be enacted in on a limiting element/contingency in PJM, then Midwest ISO would be required to add that facility as a flowgate despite the opinion of PJM or even if a transfer from Midwest ISO to PJM does not have an impact greater than the 5% threshold.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.2: Midwest ISO continues to believe that the text of this requirement is not clear. Midwest ISO asks the drafting team to consider the following language. At a minimum, establish the list of internal flowgates to create, modify, or delete at least once per calendar year.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.3: Midwest ISO continues to believe that the text of this requirement is not clear. Midwest ISO asks the drafting team to consider the following language. At a minimum, establish the list of external flowgates to create, modify, or delete that have been requested as part of R2.1.4 within thirty calendar days from the request. |

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| | | | **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.4: Both sub bullets instruct the entity to use the SOL for the flowgate. If this were to be the case, then R2.4 could be revised to just require the use of the SOL of the flowgate. Otherwise, the requirement should be revised to precisely capture the intention of the SDT.<br>**Response:** The first bullet requires that for SOLs with a limit based on megawatts, that the megawatt value be used. However, for SOLs with limits based on MVARs or other units, the flowgate limit would need to be specified as a level of flow in megawatts that supports the SOL. This is the intent of bullet two.<br><br>R5.3: How can this requirement be enforceable for entities that are non-FERC jurisdictional? We are concerned of the situation where a non-FERC jurisdictional neighboring entity doesn't provide such data to the Midwest ISO. We request clarification.<br>**Response:** Entities are only required to use AFCs they have been provided; if the information has not been provided, entities are not expected to use it. All entities within the continental United States are subject to mandatory and enforceable standards developed by the ERO. Entities outside the United States may be responsible for providing this information based on the regulatory agencies under which they operate.<br><br>R6.2/R6.4/R6.6/R7.2/R7.4/R7.6: Midwest ISO is not convinced that similar seams coordination requirements exist for the other two standards, especially for MOD-029. This continues to demonstrate that more stringent requirements are placed on MOD-030 than the other methodologies. We request to remove these requirements from MOD-030 to achieve more unbiased standards.<br>**Response:** MOD-029 is not a simulation-based methodology. As such, it is inappropriate to require the same kind of coordination as is described in MOD-028 and MOD-030. The SDT reiterates that MOD-028 does require similar coordination in R3 (generation dispatch and load for neighboring areas) and R4.3 (firm reservations from neighboring areas). |

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| | | | R11: Midwest ISO continues to question the language of this requirement for three reasons. First, the response from the SDT to our previous round of comments indicates that the TTC would remain constant because the flowgate with the lowest TFC would generally remain constant relative to each path. However, the SDT ignored the fact that the distribution factor for that same flowgate changes due to system topology changes. Hence, the TTC value will almost always change each time the model is updated, which is currently once per day as stated in R3.<br>Second, the TTC value back calculated for the Flowgate methodology is not as valuable as it is in the Rated System Path methodology or the Area Interchange Methodology. If a flowgate will never limit an ATC, why would anyone be interested to know a TTC calculated by this flowgate? As the requirement is written, the Transmission Service Provider will be expected to incur additional cost, with no benefit to either the reliability or transmission customers, to separately account for the flowgate with the smallest TFC value in order to back calculate a TTC value.<br>Third, when you use the same flowgate for all value conversions, the formula “ATC=TTC-CBMpath-TRMpath-ETCpath”still holds if you simply divide everything in formula ”AFC=TFC-CBMflowgate-TRMflowgate-ETCflowgate” by the flowgate distribution factor. However, using different flowgates would make the formula “ATC=TTC-CBM-TRM-ETC” invalid. This result eliminates the usefulness of the TTC value for the Flowgate methodology. Therefore, we request this requirement to be rewritten if the SDT believes a formula to calculate TTC must be included in the standard.<br>**Response:** The SDT recognizes the commenter’s concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>The Midwest ISO acknowledges the fact that there can be three methodologies for calculating ATC values. The Midwest ISO continues to believe that a single standard that qualitatively judges the reliability of all three methodologies is the right form to ensure reliability of the interconnected bulk power systems rather than the current approach of having a separate standard for each methodology. The Midwest ISO believes that three different standards for three different methodologies have created requirements and measures to ensure that each entity is executing its methodology per the guidelines prescribed by the standards and do not necessarily ensure reliability of the interconnected system. For example, while the MOD-030 includes several |

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| | | | requirements for Constraints (Flowgates) used in that methodology, the other standards do not include similar requirements with the premise that those methodologies do not use flowgates. For the system to be reliable, the constraints that impact an energy transfer should be the same irrespective of the methodology. The Midwest ISO sees these standards as guidelines to ensure documentation of the methodologies being executed as opposed to consistency amongst the methodologies to ensure system reliability. Midwest ISO also believes that the Flow based methodology is an advanced technique with a high level of detail and alignment with congestion management procedures such as the NERC IDC. The Midwest ISO continues to observe a significantly higher number of compliance requirements under MOD-030 than entities using a methodology that is subject to either MOD-028 or MOD-029. The Midwest ISO believes that a single ATC standard and the termination of the three previously mentioned standards would eliminate any compliance concerns related to improperly aligned standards. Flow based methodology entities under MOD 030 are held to a higher degree of compliance for volunteering to use the Flow based methodology; when regardless of methodology the highest degree of compliance must required for all three methodologies. Therefore, the Midwest ISO believes it is imperative to draft a single ATC standard that would apply to all entities regardless of the methodology selected.<br>**Response:** The SDT believes that the standards are an appropriate set of requirements that support reliability. While the SDT applauds the Midwest ISO's decision to implement an advanced technique with a high level of detail and alignment with congestion management procedures such as the NERC IDC, it notes that not all entities agree that this technique is appropriate for use by all entities. If the Midwest ISO is advocating a single methodology, the SDT suggests the Midwest ISO request this for inclusion in NERC's annual work plan. |
| **Response:** Please see in-line responses. | | | |
| Ameren Services Company | 3 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-030-1.<br>AFC is a market parameter and as such is applicable to the Transmission Service Provider.<br>Definition of an adequate flowgate population is required to adequately constrain the sale of transmission service, as such this would appear to be a market not a reliability issue.<br>Under R2 the calculation of TFC is applicable to the Transmission Operator. This is not consistent with the current version of the Functional Model. The Transmission Planner is responsible for supporting the development of TTC (TFC).<br>Under R3 the Transmission Service Provider not the Transmission Operator should be responsible for the calculation of ATC/AFC and any modeling data. This is especially |

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| | | | true when the Transmission Service Provider determines ATC for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO. That said we are aware that the oversubscription of transmission service can lead to reliability problems. AFC issues affect long term planning as well as planning in the Operating Time Horizon. |
| **Response:** The SDT has assigned the portions of the flowgate methodology related to AFC to the Transmission Service Provider.<br><br>The SDT believes the determination of flowgate is a reliability consideration, and defines how the transmission system is to be analyzed for reliability reasons with regard to determining the impacts of forecast usage of that system.<br><br>The Functional Model does not attribute the determination of TTC or TFC to any entity. As such, the SDT was required to interpret the model to determine the appropriate entity for determining TTC or TFC. Since the ratings of facilities are established by the Transmission Operator, the SDT felt it appropriate to assign the responsibility for TFC to the Transmission Operator.<br><br>Under R3, the Transmission Operator is not responsible for calculating AFC – only providing the Transmission Service Provider with a model to use in that calculation. While many entities may have delegated this task to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. NERC has attempted to address this through allowing the use of Joint Registration Organizations, where a MISO/Ameren collaboration would be sanctioned as a single entity, and then the JRO would be responsible for determining how to allocate those sanctions among participants in the JRO.<br><br>The SDT concurs that oversubscription can lead to reliability problems.<br><br>With regard to the Time Horizons used in compliance, the SDT believes the correct horizon is Operations Planning. | | | |
| Avista Corp. | 3 | Negative | The standard needs some flexibility due to regional differences. Support comments submitted by the Bonneville Power Administration. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Blachly-Lane Electric Co-op | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Bonneville Power Administration | 3 | Negative | 1. R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA's part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a |

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| | | | set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of: load, generation, configuration of extensive special protection schemes (SPS), and WECC's more stringent (greater than n-1) performance requirements determine which varying specific lines or equipment determine the capacity of the flowgate. While being made up of different named elements, BPA's existing flowgates do not always include the first three limiting Elements and their worst associated Contingency combinations, yet they still protect the area of transmission constraint. An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows: R2.4. Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate. For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate.<br>2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between "(AFCs)" and "on"; R1, where a colon is missing following |

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| | | | the "(ATCID)"; R2.1.2, where "analyses" should not be plural; and "R"s appear to be missing from all "fourth-tier" requirements (2.1.1.1 for example). |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br>The typographical errors have been corrected and an updated version of the standard has been posted for stakeholders to see – these corrections will be noted in the announcement for the recirculation ballot. | | | |
| City of McMinnville | 3 | Negative | Inappropriate methodology for WECC specific entities |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| City Public Service of San Antonio | 3 | Negative | I cannot vote for this standard as written. It needs to acknowledge definitive alternatives to ATC for regions or markets such as ERCOT where transmission service markets are not used. |
| **Response:** If ERCOT does not choose to implement this methodology, then this standard would not apply to ERCOT. If ERCOT does not have ATC Paths, or ERCOT has an associated variance, MOD-001 would not require them to select a methodology. | | | |
| Clatskanie People's Utility District | 3 | Negative | The requirement of substantial additional flowgate analysis does not add reliability and instead offers the possibility of a lower standard of understanding of system operation. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Clearwater Power Co. | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Coos-Curry Electric Cooperative, Inc | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |

| Entity | Segment | Vote | Comment |
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| Cowlitz County PUD | 3 | Negative | Cowlitz County PUD No.1 (District) Comments on MOD-030-1 Adapted from PPC Recommendations 7/29/08 The Northwest uses a flow-based ATC determination consistent with the main concepts of the proposed MOD-030 standard. However, Northwest flowgates are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition, these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology is specifically designed to the "Hub and Spoke" nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration.<br>The District disagrees with current language in R2.1.1 and R2.1.2 of MOD-030 which will require the creation of many additional "flowgates" in the Northwest with no added reliability benefits. The current proven methodology used by the Bonneville Power Administration is sufficient. Adopting R2.1.1 and R2.1.2 of MOD-030 as it now stands will unnecessarily increase workload and cost. The District is not willing to help fund complicated reliability measures where there is no benefit.<br>The District respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current methodology used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. The District supports Bonneville's proposed changes to R2.1 of this proposed standard. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Duke Energy Carolina | 3 | Affirmative | While we support approval of this standard, bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on TTC/AFC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders. |

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| **Response:** The standard does not require, but also does not forbid, such documentation. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. | | | |
| FirstEnergy Solutions | 3 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-030 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-030 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-030 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R2: Flowgate determination and calculation of TFC on flowgates. The variance would not be applicable to the TOP assignment in requirement R3, which requires the TOP to provide transmission modeling data to the TSP for the calculation of AFC. Additional Comments: In response to FE's most recent MOD-030 comments, the drafting team indicated that it felt the TOP is the appropriate entity for Requirement R2 since they are responsible for keeping the system within its operating limits. While it is true that TOPs identify SOLs and are required to maintain SOLs, the use of flowgates is primarily a market function used in evaluating interchange transactions. Per FAC-014 requirement R5.2, TOPs are required to submit SOL information to TSPs and therefore |

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<tr><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>the TSP would have the information available for the determination of Total Flow Capacity (TFC) for a given flowgate. Therefore, it is FE's position that R2 is better assigned to the TSP, but if the SDT elects not to change the standard, the above request for a MISO variance will satisfy our needs.</td></tr>
<tr><td colspan="4">Response: The SDT believes that the assignment to the Transmission Operator is correct. However, if MISO or its members wish to pursue an entity variance, they may submit a SAR requesting such a variance as defined in the NERC Reliability Standards Development procedure.</td></tr>
<tr><td>Lost River Electric Cooperative</td><td>3</td><td>Negative</td><td>We suggest a rewrite of requirement 2 that will work for the Western Interconnection.</td></tr>
<tr><td colspan="4">Response: The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.</td></tr>
<tr><td>Manitoba Hydro</td><td>3</td><td>Negative</td><td>R2.1.3 - This requirement seems onerous. Having to calculate AFCs for a flowgate that was created for a temporary system configuration, once that system configuration has resolved, seems like work for little/no benefit.<br>Response: The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.2 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of internal flowgates to create, modify or delete at least once per calendar year.<br>Response: The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.3 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of external flowgates to create, modify or delete that have been requested as part of R2.1.4 within thirty calendar days from the request.<br>Response: The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making</td></tr>
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| | | | changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.4 - It is unclear why the SDT differentiated between thermal and voltage/stability limits, when the instructions were to use the SOL regardless.<br>**Response:** The first bullet requires that for SOLs with a limit based on megawatts, that the megawatt value be used. However, for SOLs with limits based on MVARs or other units, the flowgate limit would need to be specified as a level of flow in megawatts that supports the SOL. This is the intent of bullet two.<br><br>R11 - Manitoba Hydro is not convinced that conversion from AFC to ATC can be easily calculated in a formula when different assumptions are used for calculating transmission capability. Manitoba Hydro also questions why is it only MOD 30 that requires a conversion formula? If standards are to be fair, shouldn't all three standards (MOD 28, MOD 29 and MOD 30) have as a requirement to convert transmission capability from one method to the other? Manitoba Hydro re-iterates that there shouldn't be 3 ways to calculate transmission capability. The standards should specify one methodology with consistent assumptions to preserve reliability.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. |
| **Response:** Please see in-line responses. | | | |
| MidAmerican Energy Co. | 3 | Negative | I am concerned that R2.1 requires the Transmission Operator to set up a certain number of flowgates at a minimum. With smaller Transmission Service Providers, I believe this will result unnecessarily in additional flow gates in the interconnection. I believe R2.1. should be greatly simplified, deleted, or else changes should be made to R2.1.3. Add at the end of R2.1.3 an exclusion from the requirement of adding flowgates for situations that resulted in congestion management "unless the need for Interconnection-wide congestion management was a result of unusual operating conditions that are not reasonably expected to frequently occur again (such as multiple prior outages of transmission facilities and/or critical generators)." |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, | | | |

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| the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Northern Lights Inc. | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Northern Wasco County People's Utility District (PUD) | 3 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the "Hub and Spoke" nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional "flowgates" in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Northern Wasco County PUD and other transmission customers will ultimately have to fund. Because the standard would unnecessarily impose these burdens without any incremental improvement in reliability, Northern Wasco County PUD respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. Northern Wasco County PUD supports Bonneville's proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, | | | |

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| the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Okanogan County Electric Cooperative, Inc. | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Public Utility District No. 1 of Benton County | 3 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the "Hub and Spoke" nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional "flowgates" in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Public Utility District No. 1 of Benton County (Benton PUD) and other transmission customers will ultimately have to fund. Because the standard would unnecessarily impose these burdens without any incremental improvement in reliability, Benton PUD respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. Benton PUD supports Bonneville's proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |

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| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Public Utility District No. 2 of Grant County | 3 | Negative | The additional requirements add no reliability to the system in the western interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Raft River Rural Electric Cooperative | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Salmon River Electric Cooperative | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Seattle City Light | 3 | Abstain | The draft standard, in R2.1, proposes requirements for defining flowgates that appear to be inconsistent with approaches currently used in parts of the Western Interconnection to designate flowgate elements. The linear analysis method proposed will not sufficiently consider other System Operating Limits (SOLs) that may factor into flowgate designations. Specifically, the 5% Outage Transfer Distribution Factor (OTDF) threshold proposed for identifying flowgate elements does not reflect the methods currently used in WECC to designate flowgates. While application of OTDF methods is straight-forward, and provides a simple screening tool, it may be excessively burdensome to Transmission Operators to designate and redesignate flowgates using the proposed criteria. Furthermore, it may be impractical for Transmission Service Providers to manage requests for transmission services under pro forma OATT service provisions if the proposed criteria results in a large number of flowgates subject to simultaneous limits. SCL is in agreement with the apparent purpose of the R2.1 - establishing objective criteria with distinct metrics for flowgate designation. However, |

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| | | | the requirement R2.1 proposed in the draft should be replaced, perhaps using a WECC variance, to ensure that it results in a manageable number of flowgates that promote reliable operation of the Bulk Electric System. In standards FAC-010-1 and FAC-011-1 NERC has granted Regional Differences for establishing SOLs in the Western Interconnection. A similar Regional Difference should be developed and granted with respect to the establishment and designation of flowgates in the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Umatilla Electric Cooperative | 3 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Wisconsin Public Service Corp. | 3 | Negative | R2 needs to be simplified. |
| **Response:** The SDT believes that the level of detail in R2 is required to ensure reliable analysis of the transmission system. | | | |
| Alliant Energy Corp. Services, Inc. | 4 | Negative | We believe that R2.1 requires the Transmission Operator to set up a certain number of flowgates. We believe this will require that many flowgates will be needlessly set up. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Eugene Water & Electric Board | 4 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the "Hub and Spoke" nature of the Western Interconnection system. Large generation resources are located |

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| | | | long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional “flowgates” in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Eugene Water & Electric Board (EWEB) and other transmission customers will ultimately have to fund. Because the standard would unnecessarily these burdens without any incremental improvement in reliability, EWEB respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. EWEB supports Bonnevilleâ€™s proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |
| **Response:** The SDT recognizes the commenter’s concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Pacific Northwest Generating Cooperative | 4 | Negative | We suggest a rewrite of requirement 2 that will work for the Western Interconnection. |
| **Response:** The SDT recognizes the commenter’s concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Public Power Council | 4 | Negative | The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. Northwest flowgates, however, are defined with adequate granularity to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures, loads and ratings, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider or operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the “Hub and Spoke” |

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| | | | nature of the Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional "flowgates" in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 without further revision would unnecessarily introduce significant workload, cost, and complications that Public Power Council's members and other transmission customers will ultimately have to fund. Because the standard would unnecessarily impose these burdens without any incremental improvement in reliability, Public Power Council respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The current method used by the Bonneville Power Administration is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. Public Power Council supports Bonneville's proposed approach and proposed revisions to R2.1 to address the needs of the Western Interconnection in this proposed standard. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Public Utility District No. 1 of Douglas County | 4 | Negative | We have not had sufficient time to adequately review and coordinate the issue within our region. |
| **Response:** The SDT believes that significant time has been allowed for entities to review and comment on the standard. | | | |
| Public Utility District No. 1 of Snohomish County | 4 | Negative | The District Intends To Vote As Follows: MOD-001: votes Abstain, with no comments MOD-030 comments: The Northwest uses a flow-based ATC determination consistent with the concepts of the proposed MOD-030 standard. However northwest flowgates are defined to provide adequate granularity needed to identify varying sets of critical contingencies and impacted lines under changing system conditions. Seasonal operating nomograms are developed using varying temperatures/loads/rating, generation dispatch, and contingency analysis (that meeting greater than n-1 performance requirements) to determine reliable operating capabilities. These operating nomograms allow the transmission provider/operator to maximize capacity based on specific operating conditions. In addition these seasonal operating nomograms are reviewed by the region and posted in advance of the operating season, addressing both transparency and coordinating requirements. This methodology accommodates and is tailored to the "Hub and Spoke" nature of the |

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| | | | Western Interconnection system. Large generation resources are located long distances from large loads verses the tightly meshed systems in the Eastern Interconnection where load and generation are located very close together. Due to the remote nature of generation and load in the west, transient and voltage stability considerations must be taken into consideration. If the language in R2.1.1 and R2.1.2 of MOD-030 is adopted, it will require many additional "flowgates" in the Northwest that will result in no added reliability benefits compared to the method our transmission provider has in place today. Adopting R2.1.1 and R2.1.2 of MOD-030 would unnecessarily introduce significant workload, cost, and complications that the District and other transmission customers will ultimately have to fund. For these reasons, the District believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2. The District supports the Bonneville Power Administration proposed "WECC-specific" language to address the hybrid AFC-contract-path calculation used in the Northwest. This hybrid method is ultimately more reliable, given the specific nature of the transmission and generation resources in the Western Interconnection. |
| **Response:** The SDT believes no response is necessary regarding MOD-001.<br><br>The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Seattle City Light | 4 | Abstain | The draft standard, in R2.1, proposes requirements for defining flowgates that appear to be inconsistent with approaches currently used in parts of the Western Interconnection to designate flowgate elements. The linear analysis method proposed will not sufficiently consider other System Operating Limits (SOLs) that may factor into flowgate designations. Specifically, the 5% Outage Transfer Distribution Factor (OTDF) threshold proposed for identifying flowgate elements does not reflect the methods currently used in WECC to designate flowgates. While application of OTDF methods is straight-forward, and provides a simple screening tool, it may be excessively burdensome to Transmission Operators to designate and redesignate flowgates using the proposed criteria. Furthermore, it may be impractical for Transmission Service Providers to manage requests for transmission services under pro forma OATT service provisions if the proposed criteria results in a large number of flowgates subject to simultaneous limits. SCL is in agreement with the apparent purpose of the R2.1 - establishing objective criteria with distinct metrics for flowgate designation. However, the requirement R2.1 proposed in the draft should be replaced, perhaps using a WECC variance, to ensure that it results in a manageable number of flowgates that promote |

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| | | | reliable operation of the Bulk Electric System. In standards FAC-010-1 and FAC-011-1 NERC has granted Regional Differences for establishing SOLs in the Western Interconnection. A similar Regional Difference should be developed and granted with respect to the establishment and designation of flowgates in the Western Interconnection. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| WPS Resources Corp. | 4 | Negative | R2.1 requires that the Transmission Operator shall set up a certain number of flowgates at a minimum. This could result in a certain flowgates that are not needed on an on-going basis. This requirement should be simplified, deleted, and/or changed.<br>R2.1.3. presently states that "Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology." This requirement should provide another condition when the requirement is waived by adding the following words at the end of the requirement "or unless the need for Interconnection-wide congestion management was a result of unusual operating conditions that are not reasonably expected to frequently occur again (such as multiple prior outages of transmission facilities and/or critical generators)."<br>Also, the Transmission Operator is the responsible entity for R2 through R3 for MOD-030. The responsible entity for these requirements should be the Transmission Service Provider. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>Regarding the assignment of R2 and R3 to the Transmission Operator, the Functional Model does not attribute the determination of TTC or TFC to any entity. As such, the SDT was required to interpret the model to determine the appropriate entity for determining TTC or TFC. Since the ratings of facilities are established by the Transmission Operator, the SDT felt it appropriate to assign the responsibility for TFC to the Transmission Operator. | | | |
| Avista Corp. | 5 | Negative | This standard needs to incorporate the need for regional differences. We support the comments submitted by BPA. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD- | | | |

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| 030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Bonneville Power Administration | 5 | Negative | 1. R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the eastern interconnection. However, existing practices in BPA's part of the western interconnection use flow based ATC determination which, while consistent with the concepts of this proposed standard, use a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability - where the specific characteristics of load, generation, configuration of extensive special protection schemes (SPS), and WECC's more stringent (greater than n-1) performance requirements - to determine which varying specific lines or equipment determine the capacity of the flowgate. While made up of different named elements, BPA's existing flowgates do not always include the first three limiting elements and their worst associated Contingency combinations, yet they still protect the area of transmission constraint. An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows ("red/underlined" language indicates additions): R2.4. Establish the TFC of each of the |

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| | | | defined Flowgates as equal to: For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate. For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate.<br><br>2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between "(AFCs)" and "on"; R1, where a colon is missing following the "(ATCID)"; R2.1.2, where "analyses" should not be plural; and "R"s appear to be missing from all "fourth-tier" requirements (2.1.1.1 for example). |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br>The typographical errors have been corrected and an updated version of the standard has been posted for stakeholders to see – these corrections will be noted in the announcement for the recirculation ballot. | | | |
| FirstEnergy Solutions | 5 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-030 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-030 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that |

| Entity | Segment | Vote | Comment |
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| | | | might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-030 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R2: Flowgate determination and calculation of TFC on flowgates. The variance would not be applicable to the TOP assignment in requirement R3, which requires the TOP to provide transmission modeling data to the TSP for the calculation of AFC. Additional Comments: In response to FE's most recent MOD-030 comments, the drafting team indicated that it felt the TOP is the appropriate entity for Requirement R2 since they are responsible for keeping the system within its operating limits. While it is true that TOPs identify SOLs and are required to maintain SOLs, the use of flowgates is primarily a market function used in evaluating interchange transactions. Per FAC-014 requirement R5.2, TOPs are required to submit SOL information to TSPs and therefore the TSP would have the information available for the determination of Total Flow Capacity (TFC) for a given flowgate. Therefore, it is FE's position that R2 is better assigned to the TSP, but if the SDT elects not to change the standard, the above request for a MISO variance will satisfy our needs. |
| **Response:** The SDT believes that the assignment to the Transmission Operator is correct. However, if MISO or its members wish to pursue an entity variance, they may submit a SAR requesting such a variance as defined in the NERC Reliability Standards Development procedure. | | | |
| IBERDROLA RENEWABLES | 5 | Negative | R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the Eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA's part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of: â€¢ Load â€¢ Generation â€¢ Configuration of extensive special protection schemes (SPS) and â€¢ WECC's more stringent (greater than n-1) performance requirements determine which varying specific lines or equipment determine the capacity of the flowgate. While being made up of different named elements, BPA's existing flowgates do not always include the first three limiting Elements and their worst associated contingency combinations, yet they still protect the area of transmission constraint. An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints |

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| | | | where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows ("red/underlined" language indicates additions): R2.4. Establish the TFC of each of the defined Flowgates as equal to:<br><br>– For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate.<br>– For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate.<br>2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between"(AFCs)" and "on"; R1, where a colon is missing following the "(ATCID)"; R2.1.2, where "analyse" should not be plural; and "R"s appear to be missing from all "fourth-tier" requirements (2.1.1.1 for example). |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br>The typographical errors have been corrected and an updated version of the standard has been posted for stakeholders to see – these corrections will be noted in the announcement for the recirculation ballot. | | | |
| Manitoba Hydro | 5 | Negative | R2.1.3 - This requirement seems onerous. Having to calculate AFCs for a flowgate that was created for a temporary system configuration, once that system configuration has resolved, seems like work for little/no benefit.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making |

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| | | | changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.2 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of internal flowgates to create, modify or delete at least once per calendar year.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.3 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of external flowgates to create, modify or delete that have been requested as part of R2.1.4 within thirty calendar days from the request.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes **the older version.**<br><br>R2.4 - It is unclear why the SDT differentiated between thermal and voltage/stability limits, when the instructions were to use the SOL regardless.<br>**Response:** The first bullet requires that for SOLs with a limit based on megawatts, that the megawatt value be used. However, for SOLs with limits based on MVARs or other units, the flowgate limit would need to be specified as a level of flow in megawatts that supports the SOL. This is the intent of bullet two.<br><br>R11 - Manitoba Hydro is not convinced that conversion from AFC to ATC can be easily calculated in a formula when different assumptions are used for calculating transmission capability. Manitoba Hydro also questions why is it only MOD 30 that requires a conversion formula? If standards are to be fair, shouldn't all three standards |

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| | | | (MOD 28, MOD 29 and MOD 30) have as a requirement to convert transmission capability from one method to the other? Manitoba Hydro re-iterates that there shouldn't be 3 ways to calculate transmission capability. The standards should specify one methodology with consistent assumptions to preserve reliability. **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. |
| **Response:** Please see in-line responses. | | | |
| PPL Generation LLC | 5 | Negative | We are respecting BPA's and MISO's position on this ballot in our decision to vote negative. |
| **Response:** Please see responses to BPA and MISO. | | | |
| Bonneville Power Administration | 6 | Negative | 1. R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the eastern interconnection with its commensurate characteristics. However, practices that are in place in BPA's part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of: load, generation, configuration of extensive special protection schemes (SPS), and WECC's more stringent (greater than n-1) performance requirements determine which varying specific lines or equipment determine the capacity of the flowgate. While being made up of different named elements, BPA's existing flowgates do not always include the first three limiting Elements and their worst associated Contingency combinations, yet they still protect the area of transmission constraint. An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be |

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| | | | dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are added, to replace R2.1.1-2.1.2.2 for WECC entities, R2.4 would also require modification as follows ("red/underlined" language indicates additions): R2.4. Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate. For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between "(AFCs)" and "on"; R1, where a colon is missing following the "(ATCID)"; R2.1.2, where "analyses" should not be plural; and "R"s appear to be missing from all "fourth-tier" requirements (2.1.1.1 for example).<br>**Response:** The typographical errors have been corrected and an updated version of the standard has been posted for stakeholders to see – these corrections will be noted in the announcement for the recirculation ballot. |
| **Response: Please see in-line responses.** | | | |
| FirstEnergy Solutions | 6 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-030 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered |

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| | | | entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-030 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-030 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R2: Flowgate determination and calculation of TFC on flowgates. The variance would not be applicable to the TOP assignment in requirement R3, which requires the TOP to provide transmission modeling data to the TSP for the calculation of AFC. Additional Comments: In response to FE's most recent MOD-030 comments, the drafting team indicated that it felt the TOP is the appropriate entity for Requirement R2 since they are responsible for keeping the system within its operating limits. While it is true that TOPs identify SOLs and are required to maintain SOLs, the use of flowgates is primarily a market function used in evaluating interchange transactions. Per FAC-014 requirement R5.2, TOPs are required to submit SOL information to TSPs and therefore the TSP would have the information available for the determination of Total Flow Capacity (TFC) for a given flowgate. Therefore, it is FE's position that R2 is better assigned to the TSP, but if the SDT elects not to change the standard, the above request for a MISO variance will satisfy our needs. |
| **Response:** The SDT believes that the assignment to the Transmission Operator is correct. However, if MISO or its members wish to pursue an entity variance, they may submit a SAR requesting such a variance as defined in the NERC Reliability Standards Development procedure**.** | | | |
| IBERDROLA | 6 | Negative | R2.1.1 thru R2.1.2.2 appear to well reflect existing practices in the Eastern |

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| RENEWABLES | | | interconnection with its commensurate characteristics. However, practices that are in place in BPA's part of the western interconnection use flow based ATC determination consistent with the concepts of this proposed standard, but they are based on using a set of designated flowgates that could have a varying set of critical contingencies and impacted lines depending on the system conditions. MOD-30 as written would require many new "flowgates" based on varying system conditions without providing any increased reliability benefit. This is because BPA determines their capacity based on WECC criteria which test for thermal restrictions, voltage stability, and transient stability where the specific characteristics of:<br><br>– Load – Generation<br>– Configuration of extensive special protection schemes (SPS) and<br>– WECC's more stringent (greater than n-1) performance requirements determine which varying specific lines or equipment determine the capacity of the flowgate. While being made up of different named elements, BPA's existing flowgates do not always include the first three limiting Elements and their worst associated contingency combinations, yet they still protect the area of transmission constraint.<br>An example of a basis for an ATC capacity that does not fit the proposed standard's language is a two Palo Verde nuclear unit outage in Arizona which is often the critical contingency that causes voltage stability limitations on BPA's North of Hanford Path in Washington over 1000 miles away from the Palo Verde units. While the proposed MOD-30 Flowgate Methodology may provide sufficient reliability for (n-1) thermally limited constraints where the impact of an outage is on parallel transmission, the above example describes a limiting outage that is not in the area of the transmission constraint, thus it does not make sense to define it as part of a flowgate. In regards to capacity, BPA's existing flowgates can be dynamically changed to maximize capacity based on specific operating conditions. If the language in R2.1.1 and R2.1.2 of MOD-30 is adopted, it will require defining many additional "flowgates" with no added reliability or capacity compared to the method BPA has in place today. This would unnecessarily introduce significant workload and computation to BPA and many others in the western interconnection that could, in fact, complicate the understanding of operational constraints. For these reasons, BPA believes that implementation of R2.1.1-2.1.2.2 does not make sense within WECC and respectfully requests that alternate WECC-specific requirements be added to replace R2.1.1-2.1.2.2 for WECC entities as a regional difference: RX. WECC: Results of transfer analyses, consistent with those studies required in FAC-010 and FAC-011, or their successors, for ATC Paths up to the path capability. RX.1. Only the most limiting element in a series configuration needs to be included in a Flowgate. If these "RX" requirements are |

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| | | | added, to replace R2.1.1- 2.1.2.2 for WECC entities, R2.4 would also require modification as follows (“red/underline” language indicates additions): R2.4. Establish the TFC of each of the defined Flowgates as equal to:<br>For thermal limits, the lowest System Operating Limit (SOL) included in the definition of the Flowgate.<br>For voltage or stability limits, the flow that will respect the lowest SOL included in the definition of the Flowgate.<br>**Response:** The SDT recognizes the commenter’s concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>2. Additionally, there are typos at the following locations: Applicability 4.1.1, where a space is missing between “(AFCs)” and “on”; R1, where a colon is missing following the “(ATCID)’; R2.1.2, where “analyses” should not be plural; and “R” appear to be missing from all “fourth-tier” requirements (2.1.1.1 for example).<br>**Response:** The typographical errors have been corrected and an updated version of the standard has been posted for stakeholders to see – these corrections will be noted in the announcement for the recirculation ballot. |
| **Response:** Please see in-line responses. | | | |
| Manitoba Hydro | 6 | Negative | R2.1.3 - This requirement seems onerous. Having to calculate AFCs for a flowgate that was created for a temporary system configuration, once that system configuration has resolved, seems like work for little/no benefit.<br>**Response:** The SDT recognizes the commenter’s concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.2 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of internal flowgates to create, modify or delete at least once per calendar year.<br>**Response:** The SDT recognizes the commenter’s concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making |

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| | | | changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.3 - Manitoba Hydro agrees with MISO's proposed wording changes of: At a minimum, establish the list of external flowgates to create, modify or delete that have been requested as part of R2.1.4 within thirty calendar days from the request.<br>**Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version.<br><br>R2.4 - It is unclear why the SDT differentiated between thermal and voltage/stability limits, when the instructions were to use the SOL regardless.<br>**Response:** The first bullet requires that for SOLs with a limit based on megawatts, that the megawatt value be used. However, for SOLs with limits based on MVARs or other units, the flowgate limit would need to be specified as a level of flow in megawatts that supports the SOL. This is the intent of bullet two.<br><br>R11 - Manitoba Hydro is not convinced that conversion from AFC to ATC can be easily calculated in a formula when different assumptions are used for calculating transmission capability. Manitoba Hydro also questions why is it only MOD 30 that requires a conversion formula? If standards are to be fair, shouldn't all three standards (MOD 28, MOD 29 and MOD 30) have as a requirement to convert transmission capability from one method to the other? Manitoba Hydro re-iterates that there shouldn't be 3 ways to calculate transmission capability. The standards should specify one methodology with consistent assumptions to preserve reliability.<br>**Response:** The SDT is not commenting on whether or not a TTC value has usefulness within the Flowgate methodology, and is not requiring in this standard that the TTC be calculated. However, if TTC is to be calculated, the SDT believes that this is a standardized way to do so that will result in a number that can be presented as a valid TTC. Other entities have not been requested to convert their ATCs or TTCs to AFCs or TFCs because to do so would require information that would only be available if the entities had implemented the Flowgate methodology. If Manitoba Hydro is advocating |

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| | | | a single methodology, the SDT suggests the Manitoba Hydro request this for inclusion in NERC's annual work plan. |
| **Response:** Please see in-line responses. | | | |
| Public Utility District No. 1 of Chelan County | 6 | Negative | Standard as written complicates transmission service from the Bonneville Power Authority without adding reliability. |
| **Response:** The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline, the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |
| Electric Reliability Council of Texas, Inc. | 10 | Abstain | Although stated in the Applicability Section, the Requirements and Measures contain no clear applicability only to those Transmission Operators and Transmission Service providers who utilize the Flowgate methodology in calculating Available Flowgate Capabilities. |
| **Response:** The entire standard applies only to those entities who utilize the Flowgate methodology in calculating TFC and AFC. | | | |
| Midwest Reliability Organization | 10 | Negative | The MRO is concerned with the R2.1 that requires that the Transmission Operator shall set up a certain number of flowgates at a minimum. The MRO is concerned that this will require a certain number of flowgates will be needlessly set up by smaller Transmission Service Providers as a result of this requirement. The MRO believes that this will result in a certain number of flowgates be needlessly set up. We believe that this requirement should be greatly simplified, deleted, and/or changes to R2.1.3 should be made. R2.1.3. presently states that "Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology." We believe that this requirement should provide another condition when the requirement is waived by adding the following words at the end of the requirement "or unless the need for Interconnection-wide congestion management was a result of unusual operating conditions that are not reasonably expected to frequently occur again (such as multiple prior outages of transmission facilities and/or critical generators)." Also, the MRO is concerned with the Transmission Operator being the responsible entity for R2 through R3 for MOD-030. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| **Response: The SDT recognizes the commenter's concerns. In order to be responsive to FERC Order 890 within the established filing deadline,** the SDT is not making changes to the standard at this time. However, the SDT has developed a revision to MOD-030 to address this concern (MOD-030 Version 2) and has posted that revision for a 45-day comment period. It is the intention of the SDT to pursue the approval of MOD-030 Version 2 prior to the effective date of MOD-030 Version 1, such that the new version supersedes the older version. | | | |

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| Regarding the assignment of R2 and R3 to the Transmission Operator, the Functional Model does not attribute the determination of TTC or TFC to any entity. As such, the SDT was required to interpret the model to determine the appropriate entity for determining TTC or TFC. Since the ratings of facilities are established by the Transmission Operator, the SDT felt it appropriate to assign the responsibility for TFC to the Transmission Operator. | | | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30 Day posting before board adoption. | June 21 ,2008 |
| 8. Board adopts MOD-001-1. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Rated System Path Methodology:** The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

## A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

**R1.1.1.** Includes at least:

R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)

R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)

**R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.

**R1.1.3.** Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.

**R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

**R1.1.5.** Uses Load forecast by Balancing Authority.

**R1.1.6.** Uses Transmission Facility additions and retirements.

**R1.1.7.** Uses Generation Facility additions and retirements.

**R1.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

**R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

**R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

**R2.** The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

**R2.1.1.** When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.

**R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

**R2.1.3.** Uncontrolled separation shall not occur.

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

**R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

**R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

**R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

$\mathbf{NL_F}$ is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$\mathbf{ROR_F}$ is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

$\mathbf{OS_F}$ is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

$\mathbf{NITS_{NF}}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_{NF}}$ is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

**Where**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

**R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)

**M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

**M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

**M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

**M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15

MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)

**M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

**M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30

days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)

- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2) | The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2) | The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2) | The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2) |
| R2 | One or both of the following:<br>• The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include one required item in the study report required in R2.8. | One or both of the following:<br>• The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include two required items in the study report required in R2.8. | One or both of the following:<br>• The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include three required items in the study report required in R2.8. | One or more of the following:<br>• The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator did not apply R2.7.<br>• The Transmission Operator does not include four or more required items in the study report required in R2.8 |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater). |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized. |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC Conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
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| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30 Day posting before board adoption. | June 21 ,2008 |
| 8. Board adopts MOD-001-1. | September 1, 2008 |

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## A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

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**R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

**R1.1.1.** Includes at least:

1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (~~e~~Equivalent representation is allowed.)~~.~~

1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (~~e~~Equivalent representation is allowed.)~~.~~

**R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.

**R1.1.3.** Models all generation (may be either a single generator or multiple generators)~~Facilities~~ ~~larger~~ that is greater than 20 MVA at the point of interconnection in the studied area.

**R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

**R1.1.5.** Uses Load forecast by Balancing Authority.

**R1.1.6.** Uses Transmission Facility additions and retirements.

**R1.1.7.** Uses Generation Facility additions and retirements.

**R1.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

**R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

**R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

**R2.** The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

**R2.1.1.** When modeling normal conditions, ~~do not model any~~all Transmission Elements will be modeled at or ~~above~~ below 100% of ~~its~~ their continuous rating.

**R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

**R2.1.3.** Uncontrolled separation shall not occur.

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

**R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

**R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** The Transmission Operator shall identify when~~Verify that~~ the TTC for the ATC Path being studied ~~does not~~has an adverse~~ly~~ impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. ~~.~~ The Transmission Operator shall include the resolution of this adverse impact in ~~the~~its study report for the ATC Path.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

**R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

$\mathbf{NL_F}$ is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "s~~S~~afe h~~H~~arbor t~~T~~ariff." ~~accepted by FERC.~~

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$\mathbf{ROR_F}$ is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

$\mathbf{OS_F}$ is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_{NF}$** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "s~~S~~afe h~~H~~arbor t~~T~~ariff." ~~accepted by FERC.~~

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

**Where**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

**R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks**$_{NF}$ are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows**$_{NF}$ are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, ~~used in its ATC calculations,~~ as required in R1. (R1)

**M1.2.** The Transmission model produced must include the areas listed in R1.1.1 ~~1~~ (or an equivalent representation, as described in the requirement) (R1.1)

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

**M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

**M7.** The Transmission Service Provider ~~must be capable of~~shall ~~demonstrating~~ demonstrate compliance with R5 by ~~that for any calculation of firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate~~ recalculating ~~the individual value of the~~ firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate ~~this~~ the specified value for the designated ~~hour.~~time period. The data used must meet the requirements specified in ~~the standard~~MOD-029-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is ~~, and the audited value must be~~ within +/- 15% or 15 MW, whichever is greater, of the

~~demonstrated~~ originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC~~result~~. (R5)

**M8.** The Tranasmission Service Provider ~~must be capable of demonstrating~~shall demonstrate compliance with R5 by ~~that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can~~ recalculatinge ~~the individual value of the~~ non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated ~~hour~~time period. The data used must meet the requirements specified in the ~~standard~~ MOD-029 and the ATCID.~~,~~ To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is ~~and the audited value must be~~ within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC~~demonstrated result~~. (R6)

**M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

**M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)

- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. ~~to show compliance with R5 and R6.~~ (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

~~-~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)<br>~~Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~ | The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)<br>~~Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~ | The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)<br>~~Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~ | The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)<br>~~Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~ |
| R2 | One or ~~more~~both ~~violations below constitutes a single Lower violation of R2~~of the following:<br>• The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include one required item in the study report required in R2.8. | One or ~~more~~both ~~violations below constitutes a single Moderate violation of R2~~of the following:<br>• The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include two required items in the study report required in R2.8. | One or ~~more~~both ~~violations below constitutes a single High violation of R2~~of the following:<br>• The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include three required items in the study report required in R2.8. | One or more ~~violations below constitutes a single Severe violation of R2~~of the following:<br>• The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator did not apply R2.7.<br>The Transmission Operator does not include four or more required items in the study report required |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | ~~N/A~~ | ~~N/A~~ | ~~N/A~~ | in R2.8<br>• ~~The Transmission Operator did not calculate TTC using the process described in R2.~~ |
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater). |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized. |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | 25MW, whichever is greater. | 35MW, whichever is greater. | 45MW, whichever is greater. | |
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | Paths or 1 ATC Path (whichever is greater). | greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | Paths (whichever is greater). |

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## Implementation Plan for Standard MOD-029-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-029-1 – Rated System Path Methodology, which describes the Rated System Path methodology for determining ATC.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### Retired Standards

FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-029-1 incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-029-1 becomes effective.

FAC-013-1 – Establish and Communicate Transfer Capabilities, includes two requirements. MOD-029-1 incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-029-1 becomes effective.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-029-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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## Implementation Plan for Standard MOD-029-1 (Project 2006-07)

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### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-029-1 | ■ | | ■ | | | |

## Proposed Effective Date

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RELIABILITY CORPORATION

# Summary of Process Steps Taken Following Posting of the Standards for 30-day Comment

The ATC Standard Drafting Team is developing the ATC-related standards, in part, as a response to FERC Order 890. Order 890 provided specific guidance on the timeliness of this standards development effort. The drafting team has been working to a strict time line to ensure it can file these standards in compliance with the Commission's directives, while also adhering to the NERC Reliability Standards Development Procedure.

As described in Step 8 of NERC's Reliability Standards Development Procedure,

> "Based on the comments received and field testing, the standard drafting team may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the effect or use of the standard."

When reviewing the comments received and considering changes to the standards, the drafting team also considered that any substantive changes to the requirements would require an additional 30-day comment and response period, which would eliminate the possibility of meeting the FERC's submission deadlines. The drafting team carefully weighed the reliability benefit of any changes to the standard, and attempted to limit its modifications to those that clarify or explain, rather than create new requirements or change intent. The changes to the standards made by the drafting team fall into one or more of the following categories:

- Corrections
- Redrafting of language that does not change intent
- Clarifications that better explain intent
- Modifications that change minor details, but not intent
- Modifications to ensure consistency and reduce ambiguity

The drafting team does not believe that any of the changes made to the requirements following the last comment period directly or materially affect the effect or use of the standards, but instead make the standards more clear.

The NERC Standards Committee is a stakeholder group responsible for the oversight of standards development, including evaluation of the responses to comments and any changes to the standards. As described in Step 8 of NERC's Reliability Standards Development Procedure:

> "When the Standards Committee receives a draft standard that is recommended for ballot, the Standards Committee will review the standard and recommendations of the standards process manager to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives and requirements cited in Steps 1 to 8, as applicable; has an implementation plan; and is compatible with other existing standards. If the proposed standard does not pass this review, the Standards Committee shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the Standards

Committee shall set the proposed standard for ballot as soon as the work flow will accommodate."

NERC's Standards Process Manager presented the changes described above to the Executive Committee of the NERC Standards Committee on June 19, 2008. Following review of the revisions made to the standards, comment responses, and implementation plans, the Standards Committee's Executive Committee determined that the standards had passed the review, and the changes made do not directly or materially affect the effect or use of the standards. The Standards Committee's Executive Committee directed NERC's Standards Process Manager to post the standards for 30-day pre-ballot review and to begin assembling the ballot pools necessary for balloting.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

## Reliability Standards

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| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC et al Standard - MOD-029_in |
| **Ballot Period:** | 7/21/2008 - 7/30/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 213 |
| **Total Ballot Pool:** | 225 |
| **Quorum:** | **94.67 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 92.62 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

**Summary of Ballot Results**

| | | | Affirmative | | Negative | | Abstain | |
|---|---|---|---|---|---|---|---|---|
| **Segment** | **Ballot Pool** | **Segment Weight** | **# Votes** | **Fraction** | **# Votes** | **Fraction** | **# Votes** | **No Vote** |
| 1 - Segment 1. | 63 | 1 | 38 | 0.927 | 3 | 0.073 | 18 | 4 |
| 2 - Segment 2. | 9 | 0.6 | 6 | 0.6 | 0 | 0 | 2 | 1 |
| 3 - Segment 3. | 63 | 1 | 44 | 0.936 | 3 | 0.064 | 14 | 2 |
| 4 - Segment 4. | 13 | 0.9 | 6 | 0.6 | 3 | 0.3 | 4 | 0 |
| 5 - Segment 5. | 35 | 1 | 22 | 0.957 | 1 | 0.043 | 10 | 2 |
| 6 - Segment 6. | 26 | 1 | 16 | 1 | 0 | 0 | 8 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 3 | 0.2 | 2 | 0.2 | 0 | 0 | 1 | 0 |
| 9 - Segment 9. | 5 | 0.4 | 4 | 0.4 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.4 | 4 | 0.4 | 0 | 0 | 3 | 0 |
| **Totals** | **225** | **6.5** | **142** | **6.02** | **10** | **0.48** | **61** | **12** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Ameren Services Company | Kirit S. Shah | Abstain | |
| 1 | American Electric Power | Paul B. Johnson | Affirmative | |
| 1 | American Transmission Company, LLC | Jason Shaver | Abstain | |
| 1 | Arizona Public Service Co. | Cary B. Deise | Affirmative | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Basin Electric Power Cooperative | David Rudolph | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | |
| 1 | Brazos Electric Power Cooperative, Inc. | Tony Kroskey | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Abstain | |
| 1 | Central Lincoln PUD | Ronald Beck | Affirmative | |
| 1 | Central Maine Power Company | Brian Conroy | | |
| 1 | City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power | Alan L Cooke | Abstain | |

| | | | | |
|---|---|---|---|---|
| 1 | City of Tallahassee | Gary S. Brinkworth | Abstain | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Affirmative | |
| 1 | Deseret Power | James Tucker | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | E.ON U.S. LLC | Larry Monday | Abstain | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Abstain | |
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Great River Energy | Gordon Pietsch | Abstain | |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Affirmative | |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | |
| 1 | Lincoln Electric System | Doug Bantam | Abstain | |
| 1 | Minnesota Power, Inc. | Carol Gerou | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Abstain | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Abstain | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Affirmative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Affirmative | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Affirmative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Progress Energy Carolinas | Sammy Roberts | Abstain | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Abstain | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Abstain | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | View |
| 1 | Transmission Agency of Northern California | James W Beck | Abstain | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Affirmative | |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Western Farmers Electric Coop. | Alan Derichsweiler | | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| | Independent Electricity System | | | |

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|---|---|---|---|---|
| 2 | Operator | Kim Warren | Affirmative | |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | |
| 2 | New Brunswick System Operator | Alden Briggs | Affirmative | |
| 2 | New York Independent System Operator | Gregory Campoli | Abstain | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Ameren Services Company | Mark Peters | Abstain | |
| 3 | American Electric Power | Raj Rana | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Affirmative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Blachly-Lane Electric Co-op | Bud Tracy | Affirmative | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | |
| 3 | City of McMinnville | Rick Rozanski | Affirmative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Negative | View |
| 3 | Clatskanie People's Utility District | Joseph Taffe | Negative | |
| 3 | Clearwater Power Co. | Dave Hagen | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Constellation Energy | Carolyn Ingersoll | Affirmative | |
| 3 | Consumers Energy | David A. Lapinski | Abstain | |
| 3 | Coos-Curry Electric Cooperative, Inc | Roger Meader | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | View |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Abstain | |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Grays Harbor PUD | Wesley W Gray | Abstain | |
| 3 | Great River Energy | Sam Kokkinen | Abstain | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Affirmative | |
| 3 | Lincoln Electric System | Bruce Merrill | Abstain | |
| 3 | Lost River Electric Cooperative | Richard Reynolds | Affirmative | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Abstain | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Abstain | |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | Nevada Power Co. | Sheryl Torrey | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Niagara Mohawk (National Grid Company) | Michael Schiavone | Affirmative | |
| 3 | Northern Indiana Public Service Co. | William SeDoris | Affirmative | |
| 3 | Northern Lights Inc. | Jon Shelby | Affirmative | |
| 3 | Northern Wasco County People's Utility District (PUD) | Paul Titus | Affirmative | |
| 3 | Okanogan County Electric Cooperative, Inc. | Ray Ellis | Affirmative | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Affirmative | |
| 3 | Progress Energy Carolinas | Sam Waters | Abstain | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Abstain | |
| 3 | Public Utility District No. 1 of Benton County | Gloria Bender | Affirmative | |

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|---|---|---|---|---|
| 3 | Public Utility District No. 1 of Franklin County | Linda Boomer | Affirmative | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Affirmative | |
| 3 | Raft River Rural Electric Cooperative | Heber Carpenter | Affirmative | |
| 3 | Salmon River Electric Cooperative | Ken Dizes | Affirmative | |
| 3 | Salt River Project | John T. Underhill | Affirmative | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | | |
| 3 | Umatilla Electric Cooperative | Steve Eldrige | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Abstain | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | Alliant Energy Corp. Services, Inc. | Kenneth Goldsmith | Abstain | |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Affirmative | |
| 4 | Northern California Power Agency | Fred E. Young | Abstain | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Negative | |
| 4 | Pacific Northwest Generating Cooperative | Aleka K Scott | Affirmative | |
| 4 | Public Power Council | Nancy Baker | Affirmative | |
| 4 | Public Utility District No. 1 of Douglas County | Henry E. LuBean | Negative | View |
| 4 | Public Utility District No. 1 of Snohomish County | John D. Martinsen | Affirmative | |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 4 | WPS Resources Corp. | Christopher Plante | Abstain | |
| 5 | AEP Service Corp. | Brock Ondayko | Affirmative | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | |
| 5 | City of Farmington | Clinton J Jacobs | Affirmative | |
| 5 | City of Tallahassee | Alan Gale | Abstain | |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Affirmative | |
| 5 | Deseret Power | Philip B Tice Jr | Affirmative | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Affirmative | |
| 5 | Entergy Corporation | Stanley M Jaskot | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Abstain | |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Abstain | |
| 5 | IBERDROLA RENEWABLES | Laura Beane | Affirmative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Abstain | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Abstain | |
| 5 | New York Power Authority | Gerald Mannarino | Affirmative | |
| 5 | Orlando Utilities Commission | Richard Kinas | Abstain | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Abstain | |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seattle City Light | Michael J. Haynes | Abstain | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | | |
| 5 | Southeastern Power Administration | Douglas Spencer | Affirmative | |
| 5 | Southern California Edison Co. | David Schiada | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |

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|---|---|---|---|---|
| 5 | Tenaska, Inc. | Scott M. Helyer | Abstain | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | U.S. Bureau of Reclamation | Martin Bauer | | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Affirmative | |
| 6 | AEP Marketing | Edward P. Cox | Affirmative | |
| 6 | Barry Green Consulting Inc. | Barry Green | Affirmative | |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Abstain | |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Abstain | |
| 6 | IBERDROLA RENEWABLES | Kellie J Schreiner | Affirmative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Abstain | |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Abstain | |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | Portland General Electric Co. | John Jamieson | Abstain | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Affirmative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Abstain | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | Southern California Edison Co. | Marcus V Lotto | Affirmative | |
| 6 | Tampa Electric Co. | Jose Benjamin Quintas | | |
| 6 | Tenaska Power Services Co. | Cliff T Richardson | Abstain | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Affirmative | |
| 7 | Eastman Chemical Company | Lloyd Webb | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Abstain | |
| 8 | Other | Michehl R. Gent | Affirmative | |
| 8 | Volkmann Consulting | Terry Volkmann | Affirmative | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Abstain | View |
| 10 | Midwest Reliability Organization | Larry Brusseau | Abstain | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | SERC Reliability Corporation | Carter B Edge | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Abstain | |
| | | | | |

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| Entity | Segment | Vote | Comment |
|---|---|---|---|
| Brazos Electric Power Cooperative, Inc. | 1 | Negative | A NEGATIVE vote is cast for this standard as written as it imposes obligations on entities in the ERCOT region that do not utilize ATC paths and calculation methodologies to manage congestion or for reliability operations. Our previous submitted comments suggested that applicability language be included in the requirements to recognize that such market difference exists. |
| Exelon Energy | 1 | Affirmative | General comment These standards bring the industry closer to a unified ATC calculation methodology by requiring that one of three calculation methodologies be utilized and documented. This is an improvement from where the industry is today but falls short of FERC Order No. 890. The standards still lack a requirement for ATC or AFC calculations to be consistent with criteria used in operating and planning studies for corresponding time periods. Exelon's comments reflect these deficiencies and Exelon will be making these same points to FERC if these standards are approved, requesting that the FERC direct NERC to approve the standards but modify the standards to be consistent with Order No. 890. Suggested modifications to the standards to achieve this consistency are included in our comments. MOD-028-1 Area Interchange Methodology, MOD-029-1 Rated System Path Methodology Â· Both standards need the following requirement added: Use first contingency criteria consistent with those first contingency used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems. |
| Southwest Transmission Cooperative, Inc. | 1 | Affirmative | SWTC supports all elements of MOD-29; however, there is a minority opinion that the VSLs as redrafted to accommodate the industry comments have blurred the lines of severity and grant additional discretion to the enforcement entity. |
| New York Independent System Operator | 2 | Abstain | The NYISO abstains from voting on this proposed standard. The NYISO appreciates recent feedback from the Standards Drafting Team on several rounds of comments requesting that revisions be made to the language of this proposed standard in order to: (i) expressly accommodate the NYISO's FERC-approved market design and financial reservation based open access transmission system; and (ii) eliminate any possible question as to whether the NYISO's existing approach to calculating ATC satisfies the requirements of the proposed standards. The Standards Drafting Team has indicated that it believes that the NYISO's existing procedures are compliant with the proposed standard. Nevertheless, the NYISO is abstaining in order to preserve its rights to seek a formal confirmation of its compliance from FERC or NERC. |
| City Public Service of San Antonio | 3 | Negative | I cannot vote for this standard as written. It needs to acknowledge definitive alternatives to ATC for regions or markets such as ERCOT where transmission service markets are not used. |
| Duke Energy Carolina | 3 | Affirmative | While we support approval of this standard, bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on TTC/AFC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders. |
| Wisconsin Public Service Corp. | 3 | Abstain | This is the rated system path methodology that is used in WECC. |
| Public Utility District | 4 | Negative | We have not had sufficient time to review the effects of this change and coordinate it with others in our |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| No. 1 of Douglas County | | | region. |
| Electric Reliability Council of Texas, Inc. | 10 | Abstain | Although stated in the Applicability Section, the Requirements and Measures contain no clear applicability only to those Transmission Operators and Transmission Service providers who utilize the Rated System Path methodology in calculating TTC and ATC. |
| Midwest Reliability Organization | 10 | Abstain | This is the rated system path methodology that is used in WECC. |

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

## Consideration of Comments on Initial Ballot — MOD-029-1 — Rated System Path Methodology

**Summary Consideration:** While some stakeholders suggested modifications to the standard, most stakeholders agreed with the standard as proposed and the drafting team did not make any changes to the standard.

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| Brazos Electric Power Cooperative, Inc. | 1 | Negative | A NEGATIVE vote is cast for this standard as written as it imposes obligations on entities in the ERCOT region that do not utilize ATC paths and calculation methodologies to manage congestion or for reliability operations. Our previous submitted comments suggested that applicability language be included in the requirements to recognize that such market difference exists. |
| **Response:** If ERCOT does not choose to implement this methodology, then this standard would not apply to ERCOT. If ERCOT does not have ATC Paths, or ERCOT has an associated variance, MOD-001 would not require them to select a methodology. | | | |
| Exelon Energy | 1 | Affirmative | General comment These standards bring the industry closer to a unified ATC calculation methodology by requiring that one of three calculation methodologies be utilized and documented. This is an improvement from where the industry is today but falls short of FERC Order No. 890. The standards still lack a requirement for ATC or AFC calculations to be consistent with criteria used in operating and planning studies for corresponding time periods. Exelon's comments reflect these deficiencies and Exelon will be making these same points to FERC if these standards are approved, requesting that the FERC direct NERC to approve the standards but modify the standards to be consistent with Order No. 890. Suggested modifications to the standards to achieve this consistency are included in our comments. MOD-028-1 Area Interchange Methodology, MOD-029-1 Rated System Path Methodology Â· Both standards need the following requirement added: Use first contingency criteria consistent with those first contingency used in operations studies and planning studies for the applicable time periods, including use of Special Protection Systems. |
| **Response:** The SDT believes the intent of this suggestion is addressed in MOD-001 R6 and R7. | | | |
| Southwest Transmission Cooperative, Inc. | 1 | Affirmative | SWTC supports all elements of MOD-29; however, there is a minority opinion that the VSLs as redrafted to accommodate the industry comments have blurred the lines of severity and grant additional discretion to the enforcement entity. |
| **Response:** The SDT reviewed the VSLs and concludes that they appropriately minimize the discretion of the enforcement entity. If in future comments on standards you could be more specific, that would aid the team in addressing your concerns. | | | |
| New York Independent System Operator | 2 | Abstain | The NYISO abstains from voting on this proposed standard. The NYISO appreciates recent feedback from the Standards Drafting Team on several rounds of comments requesting that revisions be made to the language of this proposed standard in order to: (i) expressly |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| | | | accommodate the NYISO's FERC-approved market design and financial reservation based open access transmission system; and (ii) eliminate any possible question as to whether the NYISO's existing approach to calculating ATC satisfies the requirements of the proposed standards. The Standards Drafting Team has indicated that it believes that the NYISO's existing procedures are compliant with the proposed standard. Nevertheless, the NYISO is abstaining in order to preserve its rights to seek a formal confirmation of its compliance from FERC or NERC. |
| **Response:** The SDT cannot provide such formal confirmation, but thanks you for your supportive comment. | | | |
| City Public Service of San Antonio | 3 | Negative | I cannot vote for this standard as written. It needs to acknowledge definitive alternatives to ATC for regions or markets such as ERCOT where transmission service markets are not used. |
| **Response:** If ERCOT does not choose to implement this methodology, then this standard would not apply to ERCOT. If ERCOT does not have ATC Paths, or ERCOT has an associated variance, MOD-001 would not require them to select a methodology. | | | |
| Duke Energy Carolina | 3 | Affirmative | While we support approval of this standard, bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on TTC/AFC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders. |
| **Response:** The standard does not require, but also does not forbid, such documentation. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. | | | |
| Wisconsin Public Service Corp. | 3 | Abstain | This is the rated system path methodology that is used in WECC. |
| **Response:** The SDT concurs. | | | |
| Public Utility District No. 1 of Douglas County | 4 | Negative | We have not had sufficient time to review the effects of this change and coordinate it with others in our region. |
| **Response:** The SDT believes that significant time has been allowed for entities to review and comment on the standard. | | | |
| Electric Reliability Council of Texas, Inc. | 10 | Abstain | Although stated in the Applicability Section, the Requirements and Measures contain no clear applicability only to those Transmission Operators and Transmission Service providers who utilize the Rated System Path methodology in calculating TTC and ATC. |
| **Response:** The entire standard applies only to those entities who utilize the Rated System Path methodology in calculating TTC and ATC. | | | |
| Midwest Reliability Organization | 10 | Abstain | This is the rated system path methodology that is used in WECC. |
| **Response:** The SDT concurs. | | | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

## A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- **R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.
- **R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.
- **R1.3.** Any contractual obligations for allocation of TTC.
- **R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.
- **R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:
  - **R1.5.1.** Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation
  - **R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation
  - **R1.5.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.5.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

**R2.** When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R3.1.2.** Load forecast for the applicable period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

**R3.2.2.** Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.** When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Use all Contingencies meeting the criteria described in the ATCID.

**R4.2.** Respect any contractual allocations of TTC.

**R4.3.** Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent

Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.

- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

**R5.** Each Transmission Operator shall establish TTC for each ATC Path as defined below: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.

**R5.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R5.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

**R6.** Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

**R6.2.** If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R6.3.** Use (as the TTC) the lesser of:

- The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or
- The sum of Facility Ratings of all ties comprising the ATC Path.

**R6.4.** For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.

[1] The Transmission operator may honor distribution factors less than 5% if desired.

**R7.** The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

**R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

**R8.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NITS_F$** is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_F$** is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R9.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources)

reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_{NF}$** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R10.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + counterflows_F$$

**Where:**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

**R11.** When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

**M4.** Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

**M5.** Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

**M6.** Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

**M7.** Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated

duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)

**M8.** Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)

**M9.** Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

**M10.** The Transmission Service Provider shall demonstrate compliance with R8 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)

**M11.** The Transmission Service Provider shall demonstrate compliance with R9 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC. (R9)

**M12.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)

**M13.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset**

Not applicable.

**1.3. Data Retention**

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R8 and R9 for the most recent 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has an ATCID but it is missing one of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements) | The Transmission Service Provider has an ATCID but it is missing two of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements) | The Transmission Service Provider has an ATCID but it is missing three of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements) | The Transmission Service Provider has an ATCID but it is missing more than three of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements) |
| R2. | The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. | The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. | One or both of the following:<br>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator Area. | One or more of the following:<br>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator Area.<br>• The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | Areas. |
| R3. | The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. | One or more of the following:<br>• The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.<br>• The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3. |
| R4. | The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater. | The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater. | The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater. | One or more of the following:<br>• The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br>• The Transmission Operator did not respect contractual allocations of TTC.<br>• The Transmission Service Provider did not model reservations' sources or sinks as described in R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater.<br>• The Transmission Operator did not use firm reservations to estimate interchange or did not |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | utilize that estimate in the TTC calculation as described in R4.3. |
| R5. | One or more of the following:<br>• The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days<br>• The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month | One or more of the following:<br>• The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days<br>• The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month | One or more of the following:<br>• The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days<br>• The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month | One or more of the following:<br>• The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 16 calendar days<br>• The Transmission Operator did not establish TTCs for use in monthly ATCs during a four or more consecutive calendar month period<br>• The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3 |
| R6. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the process specified in R6. |
| R7. | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.<br>• The Transmission Operator | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.<br>• The Transmission Operator | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.<br>• The Transmission Operator | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination.<br>• The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination. | has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination. | has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination. | daily ATC calculations.<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination.<br>• The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations. |
| R8. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R9. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | more than 25% of the value calculated in the measure or 25MW, whichever is greater. | more than 35% of the value calculated in the measure or 35MW, whichever is greater... | more than 45% of the value calculated in the measure or 45MW, whichever is greater. | |
| R10. | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |
| R11. | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

## A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

**R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

**R1.3.** Any contractual obligations for allocation of TTC.

**R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.

**R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.5.1.** Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point ~~O~~of Receipt (POR) field of the transmission reservation

**R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the Point ~~O~~of Delivery (POD) field of the transmission reservation

**R1.5.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.5.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

**R2.** When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R3.1.2.** Load forecast for the applicable period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

**R3.2.2.** Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.** When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Use all Contingencies meeting the criteria described in ~~its~~ the ATCID.

**R4.2.** Respect any contractual allocations of TTC.

**R4.3.** Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent

Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.

- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

**R5.** Each Transmission Operator shall establish TTC for each ATC Path as defined below: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** At least once within the seven calendar days ~~in the calendar week~~ prior to the specified period for TTCs used in hourly and daily ATC calculations.

**R5.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R5.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

**R6.** Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

**R6.2.** If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R6.3.** Use (as the TTC) the lesser of:

– The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or

– The sum of Facility Ratings of all ties comprising the ATC Path.

**R6.4.** For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission ~~Operator~~ Service Provider so the TTC does not exceed ~~that Transmission Operator's~~ each Transmission Service Provider's contractual rights.

[1] The Transmission operator may honor distribution factors less than 5% if desired.

**R7.** The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

**R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

**R8.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

$\mathbf{NITS_F}$ is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

$\mathbf{GF_F}$ is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or ~~"S~~safe ~~Harbor~~ harbor ~~Tariff~~tariff~~"~~ ~~accepted by FERC~~ on ATC Paths that serve as interfaces with other Balancing Authorities.

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$\mathbf{ROR_F}$ is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

$\mathbf{OS_F}$ is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R9.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

$\mathbf{NITS_{NF}}$ is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources)

reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_{NF}$** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or ~~"~~s~~S~~afe ~~Harbor~~ harbor ~~Tariff~~tariff~~"~~ ~~accepted by FERC~~ on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R10.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

**Where:**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

**R11.** When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

**M4.** Each Transmission Operator shall provide the contingencies used in determining TTC and ~~its~~ the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

**M5.** Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

**M6.** Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

**M7.** Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated

duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)

**M8.** Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)

**M9.** Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

**M10.** The ~~T~~Transmission Service Provider ~~must be capable of demonstrating~~shall demonstrate compliance with R8 by ~~that for any calculation of firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the firm ETC for~~ recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate ~~this~~ the specified value for the designated ~~hour~~time period. The data used must meet the requirements specified in ~~the standard~~MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated ~~, and the audited~~ value ~~must~~ that is~~be~~ within +/- 15% or 15 MW, whichever is greater, of the ~~demonstrated result~~originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)

~~**M10.**~~ ~~(R8)~~

**M11.** The Transmission Service Provider ~~must be capable of demonstrating~~shall demonstrate compliance with R9 by ~~that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can~~ recalculateing ~~the individual value of the~~ non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate ~~this~~ the specified value for the designated ~~hour~~time period. The data used must meet the requirements specified in ~~the standard~~MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is ~~, and the audited value must be~~ within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC~~demonstrated result~~. (R9)

**M12.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)

**M13.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in ~~with~~ R8 and R9 for the most recent ~~sixty~~ 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has an ATCID but it is missing one of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements)<br>~~The Transmission Service Provider has an ATCID that meets the intent of Requirement 1 but the ATCID is missing some minor information.~~ | The Transmission Service Provider has an ATCID but it is missing two of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements)<br>~~The Transmission Service Provider has an ATCID but it is missing one of the four required elements in R1.~~ | The Transmission Service Provider has an ATCID but it is missing three of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements)<br>~~The Transmission Service Provider has an ATCID but it is missing two of the four required elements in R1.~~ | The Transmission Service Provider has an ATCID but it is missing more than three of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements)<br>~~The Transmission Service Provider has an ATCID but it is missing three or more of the four required elements in R1.~~ |
| R2. | The Transmission Operator ~~utilized~~ used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>~~Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled~~used. | The Transmission Operator ~~utilized~~ used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>~~Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled~~used. | One or both of the following:<br>• The Transmission Operator ~~utilized~~ used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>~~OR~~<br>• The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) | One or more of the following:<br>• The Transmission Operator ~~utilized~~ used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>~~OR~~<br>• The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability |

| R # | Lower VSL | Moderate ~~VSL~~ | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | for one adjacent Reliability Coordinator ~~area~~Area.<br>~~Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled~~used~~.~~ | Coordinator ~~area~~Area.<br>~~OR~~<br>• The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator ~~areas~~Areas.<br>~~Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled~~used~~.~~ |
| R3. | The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. | One or more ~~violations below constitutes a single violation of R3~~of the following:~~:~~<br>• The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.<br>~~OR~~<br>• The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | The Transmission ~~Service Provider~~Operator did not model reservations' sources or sinks as described in R5.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater~~.~~. | The Transmission ~~Service Provider~~Operator did not model reservations' sources or sinks as described in R5.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater~~.~~. | The Transmission ~~Service Provider~~Operator did not model reservations' sources or sinks as described in R5.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater~~.~~. | One or more of the following:<br>• The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br>~~OR~~<br>• The Transmission Operator did not respect contractual allocations of TTC.<br>~~OR~~<br>• The Transmission ~~Service Provider~~Operator did not model reservations' sources or sinks as described in ~~R5~~R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater.<br>~~OR~~<br>• The Transmission Operator did not use firm reservations to estimate interchange or did not utilize that estimate in the TTC calculation as described in R4.3. |
| R5. | One or more of the following:<br>• The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days | One or more of the following:<br>• The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days | One or more of the following:<br>• The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days | One or more of the following:<br>• The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 16 calendar days<br>• The Transmission Operator did not establish TTCs for |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | • The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month<br>~~N/A~~ | • The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month ~~N/A~~ | • The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month<br>~~N/A~~ | use in monthly ATCs during a four or more consecutive calendar month period<br>• The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3<br>~~The Transmission Operator did not establish TTCs within the minimum time frames specified in R5.~~ |
| R6. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the process specified in R6. |
| R7. | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.<br>~~OR~~<br>• The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.<br>~~OR~~<br>• The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.<br>~~OR~~<br>• The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination.<br>~~OR~~<br>• The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations.<br>~~OR~~<br>• The Transmission Operator provided its Transmission Service Provider with its ATC |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | than 14 calendar days since their determination. | more than 21 calendar days after their determination. | more than 28 calendar days after their determination. | Path TTCs used in monthly ATC ~~calculations more~~calculations more than 28 calendar days after their determination. ~~OR~~ • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations. |
| R8. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in ~~M9~~ M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in ~~M9~~ M10 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in ~~M9~~ M10 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in ~~M9~~ M10 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R9. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in ~~M10~~ M11 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in ~~M10~~ M11 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in ~~M10~~ M11 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in ~~M10~~ M11 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | but not more than 35% of the value calculated in the measure or 35MW, whichever is greater... | but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | |
| R10. | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |
| R11. | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |

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## Implementation Plan for Standard MOD-028-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-028-1 – Area Interchange Methodology, which describes the Area Interchange methodology (previously referred to as the Network Response ATC methodology) for determining ATC.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### Retired Standards

FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-028-1 incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

FAC-013-1 – Establish and Communicate Transfer Capabilities, includes two requirements. MOD-028-1 incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-028-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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|---|---|---|---|---|---|---|
| MOD-028-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Summary of Process Steps Taken Following Posting of the Standards for 30-day Comment

The ATC Standard Drafting Team is developing the ATC-related standards, in part, as a response to FERC Order 890. Order 890 provided specific guidance on the timeliness of this standards development effort. The drafting team has been working to a strict time line to ensure it can file these standards in compliance with the Commission's directives, while also adhering to the NERC Reliability Standards Development Procedure.

As described in Step 8 of NERC's Reliability Standards Development Procedure,

> "Based on the comments received and field testing, the standard drafting team may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the effect or use of the standard."

When reviewing the comments received and considering changes to the standards, the drafting team also considered that any substantive changes to the requirements would require an additional 30-day comment and response period, which would eliminate the possibility of meeting the FERC's submission deadlines. The drafting team carefully weighed the reliability benefit of any changes to the standard, and attempted to limit its modifications to those that clarify or explain, rather than create new requirements or change intent. The changes to the standards made by the drafting team fall into one or more of the following categories:

- Corrections
- Redrafting of language that does not change intent
- Clarifications that better explain intent
- Modifications that change minor details, but not intent
- Modifications to ensure consistency and reduce ambiguity

The drafting team does not believe that any of the changes made to the requirements following the last comment period directly or materially affect the effect or use of the standards, but instead make the standards more clear.

The NERC Standards Committee is a stakeholder group responsible for the oversight of standards development, including evaluation of the responses to comments and any changes to the standards. As described in Step 8 of NERC's Reliability Standards Development Procedure:

> "When the Standards Committee receives a draft standard that is recommended for ballot, the Standards Committee will review the standard and recommendations of the standards process manager to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives and requirements cited in Steps 1 to 8, as applicable; has an implementation plan; and is compatible with other existing standards. If the proposed standard does not pass this review, the Standards Committee shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the Standards

> Committee shall set the proposed standard for ballot as soon as the work flow will accommodate."

NERC's Standards Process Manager presented the changes described above to the Executive Committee of the NERC Standards Committee on June 19, 2008. Following review of the revisions made to the standards, comment responses, and implementation plans, the Standards Committee's Executive Committee determined that the standards had passed the review, and the changes made do not directly or materially affect the effect or use of the standards. The Standards Committee's Executive Committee directed NERC's Standards Process Manager to post the standards for 30-day pre-ballot review and to begin assembling the ballot pools necessary for balloting.

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## Reliability Standards



| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC et al Standard - MOD-028_in |
| **Ballot Period:** | 7/21/2008 - 7/30/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 212 |
| **Total Ballot Pool:** | 224 |
| **Quorum:** | **94.64 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 79.47 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

**Summary of Ballot Results**

| | | | Affirmative | | Negative | | Abstain | |
|---|---|---|---|---|---|---|---|---|
| **Segment** | **Ballot Pool** | **Segment Weight** | **# Votes** | **Fraction** | **# Votes** | **Fraction** | **# Votes** | **No Vote** |
| 1 - Segment 1. | 62 | 1 | 24 | 0.8 | 6 | 0.2 | 28 | 4 |
| 2 - Segment 2. | 9 | 0.4 | 4 | 0.4 | 0 | 0 | 4 | 1 |
| 3 - Segment 3. | 63 | 1 | 26 | 0.839 | 5 | 0.161 | 30 | 2 |
| 4 - Segment 4. | 13 | 0.7 | 2 | 0.2 | 5 | 0.5 | 6 | 0 |
| 5 - Segment 5. | 36 | 1 | 16 | 0.842 | 3 | 0.158 | 15 | 2 |
| 6 - Segment 6. | 25 | 1 | 11 | 0.846 | 2 | 0.154 | 10 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 3 | 0.2 | 2 | 0.2 | 0 | 0 | 1 | 0 |
| 9 - Segment 9. | 5 | 0.4 | 4 | 0.4 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.5 | 4 | 0.4 | 1 | 0.1 | 2 | 0 |
| **Totals** | **224** | **6.2** | **93** | **4.927** | **22** | **1.273** | **97** | **12** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Ameren Services Company | Kirit S. Shah | Abstain | |
| 1 | American Electric Power | Paul B. Johnson | Affirmative | |
| 1 | American Transmission Company, LLC | Jason Shaver | Abstain | |
| 1 | Arizona Public Service Co. | Cary B. Deise | Abstain | |
| 1 | Avista Corp. | Scott Kinney | Abstain | |
| 1 | Basin Electric Power Cooperative | David Rudolph | Negative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Abstain | |
| 1 | Brazos Electric Power Cooperative, Inc. | Tony Kroskey | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Abstain | |
| 1 | Central Lincoln PUD | Ronald Beck | Abstain | |
| 1 | Central Maine Power Company | Brian Conroy | | |
| 1 | City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power | Alan L Cooke | Abstain | |

| | | | | |
|---|---|---|---|---|
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | E.ON U.S. LLC | Larry Monday | Abstain | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Abstain | |
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Affirmative | |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Minnesota Power, Inc. | Carol Gerou | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Abstain | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Affirmative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Abstain | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Abstain | |
| 1 | PacifiCorp | Robert Williams | Abstain | |
| 1 | Platte River Power Authority | John C Collins | Abstain | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Progress Energy Carolinas | Sammy Roberts | Abstain | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Abstain | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Abstain | |
| 1 | Salt River Project | Robert Kondziolka | Abstain | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Abstain | |
| 1 | Seattle City Light | Christopher M. Turner | Abstain | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Abstain | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Abstain | View |
| 1 | Transmission Agency of Northern California | James W Beck | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Abstain | |
| 1 | Western Area Power Administration | Robert Temple | Abstain | |
| 1 | Western Farmers Electric Coop. | Alan Derichsweiler | | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | | |
| 2 | British Columbia Transmission Corporation | Phil Park | Abstain | |
| 2 | California ISO | David Hawkins | Abstain | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | |
| 2 | New Brunswick System Operator | Alden Briggs | Affirmative | |
| 2 | New York Independent System Operator | Gregory Campoli | Abstain | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Ameren Services Company | Mark Peters | Abstain | |
| 3 | American Electric Power | Raj Rana | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Abstain | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Blachly-Lane Electric Co-op | Bud Tracy | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Abstain | |
| 3 | City of McMinnville | Rick Rozanski | Affirmative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Negative | View |
| 3 | Clatskanie People's Utility District | Joseph Taffe | Abstain | |
| 3 | Clearwater Power Co. | Dave Hagen | Abstain | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Constellation Energy | Carolyn Ingersoll | Affirmative | |
| 3 | Consumers Energy | David A. Lapinski | Abstain | |
| 3 | Coos-Curry Electric Cooperative, Inc | Roger Meader | Abstain | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | View |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Abstain | |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Grays Harbor PUD | Wesley W Gray | Abstain | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Affirmative | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Lost River Electric Cooperative | Richard Reynolds | Abstain | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Abstain | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Affirmative | |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | Nevada Power Co. | Sheryl Torrey | Abstain | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Niagara Mohawk (National Grid Company) | Michael Schiavone | Affirmative | |
| 3 | Northern Indiana Public Service Co. | William SeDoris | Affirmative | |
| 3 | Northern Lights Inc. | Jon Shelby | Abstain | |
| 3 | Northern Wasco County People's Utility District (PUD) | Paul Titus | Abstain | |
| 3 | Okanogan County Electric Cooperative, Inc. | Ray Ellis | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Abstain | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Affirmative | |
| 3 | Progress Energy Carolinas | Sam Waters | Abstain | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Abstain | |
| 3 | Public Utility District No. 1 of Benton County | Gloria Bender | Abstain | |
| | Public Utility District No. 1 of Franklin | | | |

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|---|---|---|---|---|
| 3 | County | Linda Boomer | Abstain | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Abstain | |
| 3 | Raft River Rural Electric Cooperative | Heber Carpenter | Abstain | |
| 3 | Salmon River Electric Cooperative | Ken Dizes | Abstain | |
| 3 | Salt River Project | John T. Underhill | Abstain | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Abstain | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | | |
| 3 | Umatilla Electric Cooperative | Steve Eldrige | Abstain | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | Alliant Energy Corp. Services, Inc. | Kenneth Goldsmith | Negative | View |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Affirmative | |
| 4 | Northern California Power Agency | Fred E. Young | Abstain | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Negative | |
| 4 | Pacific Northwest Generating Cooperative | Aleka K Scott | Abstain | |
| 4 | Public Power Council | Nancy Baker | Abstain | |
| 4 | Public Utility District No. 1 of Douglas County | Henry E. LuBean | Negative | View |
| 4 | Public Utility District No. 1 of Snohomish County | John D. Martinsen | Abstain | |
| 4 | Seattle City Light | Hao Li | Abstain | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 4 | WPS Resources Corp. | Christopher Plante | Negative | View |
| 5 | AEP Service Corp. | Brock Ondayko | Affirmative | |
| 5 | Avista Corp. | Edward F. Groce | Abstain | |
| 5 | BC Hydro and Power Authority | Clement Ma | Abstain | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Abstain | |
| 5 | City of Farmington | Clinton J Jacobs | Affirmative | |
| 5 | City of Tallahassee | Alan Gale | Abstain | |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Affirmative | |
| 5 | Deseret Power | Philip B Tice Jr | Abstain | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Affirmative | |
| 5 | Entergy Corporation | Stanley M Jaskot | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Abstain | |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | IBERDROLA RENEWABLES | Laura Beane | Abstain | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Abstain | |
| 5 | New York Power Authority | Gerald Mannarino | Affirmative | |
| 5 | Orlando Utilities Commission | Richard Kinas | Abstain | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Abstain | |
| 5 | Salt River Project | Glen Reeves | Abstain | |
| 5 | Seattle City Light | Michael J. Haynes | Abstain | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | | |
| 5 | Southeastern Power Administration | Douglas Spencer | Affirmative | |
| 5 | Southern California Edison Co. | David Schiada | Abstain | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |

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|---|---|---|---|---|
| 5 | Tenaska, Inc. | Scott M. Helyer | Abstain | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | U.S. Bureau of Reclamation | Martin Bauer | | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Affirmative | |
| 6 | AEP Marketing | Edward P. Cox | Affirmative | |
| 6 | Barry Green Consulting Inc. | Barry Green | Affirmative | |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Abstain | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Abstain | |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | IBERDROLA RENEWABLES | Kellie J Schreiner | Abstain | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Abstain | |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Affirmative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Abstain | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Abstain | |
| 6 | Salt River Project | Mike Hummel | Abstain | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | Southern California Edison Co. | Marcus V Lotto | Abstain | |
| 6 | Tampa Electric Co. | Jose Benjamin Quintas | | |
| 6 | Tenaska Power Services Co. | Cliff T Richardson | Abstain | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Affirmative | |
| 7 | Eastman Chemical Company | Lloyd Webb | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Abstain | |
| 8 | Other | Michehl R. Gent | Affirmative | |
| 8 | Volkmann Consulting | Terry Volkmann | Affirmative | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Abstain | View |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | SERC Reliability Corporation | Carter B Edge | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Abstain | |
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| Entity | Segment | Vote | Comment |
|---|---|---|---|
| Brazos Electric Power Cooperative, Inc. | 1 | Negative | A NEGATIVE vote is cast for this standard as written as it imposes obligations on entities in the ERCOT region that do not utilize ATC paths and calculation methodologies to manage congestion or for reliability operations. Our previous submitted comments suggested that applicability language be included in the requirements to recognize that such market difference exists. |
| Exelon Energy | 1 | Affirmative | General comment These standards bring the industry closer to a unified ATC calculation methodology by requiring that one of three calculation methodologies be utilized and documented. This is an improvement from where the industry is today but falls short of FERC Order No. 890. The standards still lack a requirement for ATC or AFC calculations to be consistent with criteria used in operating and planning studies for corresponding time periods. Exelon's comments reflect these deficiencies and Exelon will be making these same points to FERC if these standards are approved, requesting that the FERC direct NERC to approve the standards but modify the standards to be consistent with Order No. 890. Suggested modifications to the standards to achieve this consistency are included in our comments. MOD-028-1 Area Interchange Methodology, MOD-029-1 Rated System Path Methodology and MOD-030-1 Flowgate Methodology In the “Purpose” section, all three standards state, “To increase consistency and reliability in the development and documentation of Transfer Capability calculations for “short-term use”. Short-term is an undefined term and it applies that these standards do not apply to ATC calculations beyond the “short-term” period. In is recommended that the phrase for “short-term use” be removed from the purpose. |
| Great River Energy | 1 | Negative | GRE is concerned with the Transmission Operator being the responsible entity for MOD-028_R2-R7. GRE believes that the responsible entity for these requirements should be the Transmission Service Provider. It is GRE's opinion that a standard should not knowingly be written in a manner that requires delegation agreements to be created for a large number of responsible entities, doing so is an inefficient use of resources. |
| Sierra Pacific Power Co. | 1 | Affirmative | Affirmative vote with comment: The severity levels surrounding R1 still appear to imply that all of the sub-items of R1.1 are expected to be used in the TRMID. It must be clear that it does not constitute a violation if various of these sub-items are not applicable to the TRMID used by the entity. Clarify that this is "as applicable" or "as determined by the entity". |
| Southwest Transmission Cooperative, Inc. | 1 | Abstain | No WECC entity that has definitely elected to use MOD-28; therefore, we recommend no action. |
| New York Independent System Operator | 2 | Abstain | The NYISO abstains from voting on this proposed standard. The NYISO appreciates recent feedback from the Standards Drafting Team on several rounds of comments requesting that revisions be made to the language of this proposed standard in order to: (i) expressly accommodate the NYISO’s FERC-approved market design and financial reservation based open access transmission system; and (ii) eliminate any possible question as to whether the NYISO’s existing approach to calculating ATC satisfies the requirements of the proposed standards. The Standards Drafting Team has indicated that it believes that the NYISO’s existing procedures are compliant with the proposed standard. Nevertheless, the NYISO is |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| | | | abstaining in order to preserve its rights to seek a formal confirmation of its compliance from FERC or NERC. |
| City Public Service of San Antonio | 3 | Negative | I cannot vote for this standard as written. It needs to acknowledge definitive alternatives to ATC for regions or markets such as ERCOT where transmission service markets are not used. |
| Duke Energy Carolina | 3 | Affirmative | While we support approval of this standard, bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on TTC/AFC, documentation should be required by the standard for those facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders. |
| Lincoln Electric System | 3 | Negative | LES is concerned with the Transmission Operator being the responsible entity for R2 through R7 for MOD-028. We believe that the responsible entity for these requirements should be the Transmission Service Provider |
| Wisconsin Public Service Corp. | 3 | Negative | The Transmission Service Provider should be the responsible entity for R2 through R7 for MOD-028, not the Transmission Operator. |
| Alliant Energy Corp. Services, Inc. | 4 | Negative | We believe the responsible entity for R2 thru R7 should be the Transmission Service Provider, not the Transmission Operator. |
| Public Utility District No. 1 of Douglas County | 4 | Negative | We have not had sufficient time to review the effects of this change and coordinate it with others in our region. |
| WPS Resources Corp. | 4 | Negative | Requirements R2 through R7 list the responsible entity as the Transmission Owner. The Transmission Service Provider should be the responsible entity. |
| Lincoln Electric System | 5 | Negative | LES is concerned with the Transmission Operator being the responsible entity for R2 through R7 for MOD-028. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| Lincoln Electric System | 6 | Negative | LES is concerned with the Transmission Operator being the responsible entity for R2 through R7 for MOD-028. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| Electric Reliability Council of Texas, Inc. | 10 | Abstain | Although stated in the Applicability Section of the Standard, the Requirements and Measures contain no clear applicability only to those Transmission Operators and Transmission Service Providers who utilize AIM in calculating ATC and TTC for their transmission system and market operations. |
| Midwest Reliability Organization | 10 | Negative | The MRO is concerned with the Transmission Operator being the responsible entity for R2 through R7 for MOD-028. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Consideration of Comments on Initial Ballot — MOD-028-1 — Area Interchange Methodology

**Summary Consideration:** While some stakeholders suggested modifications to the standard, most stakeholders agreed with the standard as proposed and the drafting team did not make any changes to the standard.

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| Brazos Electric Power Cooperative, Inc. | 1 | Negative | A NEGATIVE vote is cast for this standard as written as it imposes obligations on entities in the ERCOT region that do not utilize ATC paths and calculation methodologies to manage congestion or for reliability operations. Our previous submitted comments suggested that applicability language be included in the requirements to recognize that such market difference exists. |
| **Response**: If ERCOT does not choose to implement this methodology, then this standard would not apply to ERCOT. If ERCOT does not have ATC Paths, or ERCOT has an associated variance, MOD-001 would not require them to select a methodology. | | | |
| Exelon Energy | 1 | Affirmative | General comment These standards bring the industry closer to a unified ATC calculation methodology by requiring that one of three calculation methodologies be utilized and documented. This is an improvement from where the industry is today but falls short of FERC Order No. 890. The standards still lack a requirement for ATC or AFC calculations to be consistent with criteria used in operating and planning studies for corresponding time periods. Exelon's comments reflect these deficiencies and Exelon will be making these same points to FERC if these standards are approved, requesting that the FERC direct NERC to approve the standards but modify the standards to be consistent with Order No. 890.<br><br>Suggested modifications to the standards to achieve this consistency are included in our comments. MOD-028-1 Area Interchange Methodology, MOD-029-1 Rated System Path Methodology and MOD-030-1 Flowgate Methodology In the “Purpose” section, all three standards state, “To increase consistency and reliability in the development and documentation of Transfer Capability calculations for “short-term use”. Short-term is an undefined term and it applies that these standards do not apply to ATC calculations beyond the “short-term” period. In is recommended that the phrase for “short-term use” be removed from the purpose. |
| **Response**: The SDT does not believe the term used in the Purpose statement of the standard is confusing. The requirements themselves specify all time periods for which entities will be expected to comply. | | | |
| Great River Energy | 1 | Negative | GRE is concerned with the Transmission Operator being the responsible entity for MOD- |

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| Entity | Segment | Vote | Comment |
|---|---|---|---|
| | | | 028_R2-R7. GRE believes that the responsible entity for these requirements should be the Transmission Service Provider. It is GRE's opinion that a standard should not knowingly be written in a manner that requires delegation agreements to be created for a large number of responsible entities, doing so is an inefficient use of resources. |
| **Response**: The SDT believes the Functional Model indicates these requirements should apply to the Transmission Operator. While many entities may have delegated these tasks to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Note that given the lack of consistency in how the industry performs these functions, a change to the Transmission Operator could require other entities to enter into similar delegation agreements to address that situation. If an entity does not want delegation agreements, then an entity variance or the use of a Joint Registration Organization may be appropriate. | | | |
| Sierra Pacific Power Co. | 1 | Affirmative | Affirmative vote with comment: The severity levels surrounding R1 still appear to imply that all of the sub-items of R1.1 are expected to be used in the TRMID. It must be clear that it does not constitute a violation if various of these sub-items are not applicable to the TRMID used by the entity. Clarify that this is "as applicable" or "as determined by the entity". |
| **Response**: This comment has been addressed with the MOD-008 standard. | | | |
| Southwest Transmission Cooperative, Inc. | 1 | Abstain | No WECC entity that has definitely elected to use MOD-28; therefore, we recommend no action. |
| **Response**: The SDT concurs. | | | |
| New York Independent System Operator | 2 | Abstain | The NYISO abstains from voting on this proposed standard. The NYISO appreciates recent feedback from the Standards Drafting Team on several rounds of comments requesting that revisions be made to the language of this proposed standard in order to: (i) expressly accommodate the NYISO's FERC-approved market design and financial reservation based open access transmission system; and (ii) eliminate any possible question as to whether the NYISO's existing approach to calculating ATC satisfies the requirements of the proposed standards. The Standards Drafting Team has indicated that it believes that the NYISO's existing procedures are compliant with the proposed standard. Nevertheless, the NYISO is abstaining in order to preserve its rights to seek a formal confirmation of its compliance from FERC or NERC. |
| **Response**: The SDT cannot provide such formal confirmation, but thanks you for your supportive comment. | | | |
| City Public Service of San Antonio | 3 | Negative | I cannot vote for this standard as written. It needs to acknowledge definitive alternatives to ATC for regions or markets such as ERCOT where transmission service markets are not used. |
| **Response**: If ERCOT does not choose to implement this methodology, then this standard would not apply to ERCOT. If ERCOT does not have ATC Paths, or ERCOT has an associated variance, MOD-001 would not require them to select a methodology. | | | |
| Duke Energy Carolina | 3 | Affirmative | While we support approval of this standard, bulk electric system facilities 161kV and below may have significant network response. Since these facilities may have significant impact on TTC/AFC, documentation should be required by the standard for those |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| | | | facilities 161kV and below which are equivalized. This will provide transparency for impacted stakeholders. |
| **Response**: The standard does not require, but also does not forbid, such documentation. If a region believes that facilities 161 kV and below should not be equivalenced or more transparency is required, then that region can write a regional standard that is more stringent. | | | |
| Lincoln Electric System | 3 | Negative | LES is concerned with the Transmission Operator being the responsible entity for R2 through R7 for MOD-028. We believe that the responsible entity for these requirements should be the Transmission Service Provider |
| **Response**: The SDT does not find a clear rationale for selecting the Transmission Service Provider as the entity responsible for calculating TTC. The Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints.<br><br>If an entity believes the TSP to be the appropriate entity, then options for delegation of this task exist. The Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service Provider agreeing to take on responsibility for this requirement through written contract. If an entity does not want delegation agreements, then an entity variance or the use of a Joint Registration Organization may be appropriate. | | | |
| Wisconsin Public Service Corp. | 3 | Negative | The Transmission Service Provider should be the responsible entity for R2 through R7 for MOD-028, not the Transmission Operator. |
| **Response**: The SDT does not find a clear rationale for selecting the Transmission Service Provider as the entity responsible for calculating TTC. The Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints.<br><br>If an entity believes the TSP to be the appropriate entity, then options for delegation of this task exist. The Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service Provider agreeing to take on responsibility for this requirement through written contract. If an entity does not want delegation agreements, then an entity variance or the use of a Joint Registration Organization may be appropriate. | | | |
| Alliant Energy Corp. Services, Inc. | 4 | Negative | We believe the responsible entity for R2 thru R7 should be the Transmission Service Provider, not the Transmission Operator. |
| **Response**: The SDT does not find a clear rationale for selecting the Transmission Service Provider as the entity responsible for calculating TTC. The Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints.<br><br>If an entity believes the TSP to be the appropriate entity, then options for delegation of this task exist. The Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service Provider agreeing to take on | | | |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| responsibility for this requirement through written contract. If an entity does not want delegation agreements, then an entity variance or the use of a Joint Registration Organization may be appropriate. | | | |
| Public Utility District No. 1 of Douglas County | 4 | Negative | We have not had sufficient time to review the effects of this change and coordinate it with others in our region. |
| **Response**: The SDT believes that significant time has been allowed for entities to review and comment on the standard. | | | |
| WPS Resources Corp. | 4 | Negative | Requirements R2 through R7 list the responsible entity as the Transmission Owner. The Transmission Service Provider should be the responsible entity. |
| **Response**: The SDT does not find a clear rationale for selecting the Transmission Service Provider as the entity responsible for calculating TTC. The Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints.<br><br>If an entity believes the TSP to be the appropriate entity, then options for delegation of this task exist. The Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service Provider agreeing to take on responsibility for this requirement through written contract. If an entity does not want delegation agreements, then an entity variance or the use of a Joint Registration Organization may be appropriate. | | | |
| Lincoln Electric System | 5 | Negative | LES is concerned with the Transmission Operator being the responsible entity for R2 through R7 for MOD-028. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| **Response**: The SDT does not find a clear rationale for selecting the Transmission Service Provider as the entity responsible for calculating TTC. The Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints.<br><br>If an entity believes the TSP to be the appropriate entity, then options for delegation of this task exist. The Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service Provider agreeing to take on responsibility for this requirement through written contract. If an entity does not want delegation agreements, then an entity variance or the use of a Joint Registration Organization may be appropriate. | | | |
| Lincoln Electric System | 6 | Negative | LES is concerned with the Transmission Operator being the responsible entity for R2 through R7 for MOD-028. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| **Response**: The SDT does not find a clear rationale for selecting the Transmission Service Provider as the entity responsible for calculating TTC. The Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints. | | | |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| If an entity believes the TSP to be the appropriate entity, then options for delegation of this task exist. The Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service Provider agreeing to take on responsibility for this requirement through written contract. If an entity does not want delegation agreements, then an entity variance or the use of a Joint Registration Organization may be appropriate. | | | |
| Electric Reliability Council of Texas, Inc. | 10 | Abstain | Although stated in the Applicability Section of the Standard, the Requirements and Measures contain no clear applicability only to those Transmission Operators and Transmission Service Providers who utilize AIM in calculating ATC and TTC for their transmission system and market operations. |
| **Response**: The Applicability Section of the standard applies to the entire standard. | | | |
| Midwest Reliability Organization | 10 | Negative | The MRO is concerned with the Transmission Operator being the responsible entity for R2 through R7 for MOD-028. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| **Response**: The SDT does not find a clear rationale for selecting the Transmission Service Provider as the entity responsible for calculating TTC. The Functional Model requires the Transmission Operator to determine SOLs (Defines System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator), which we believe ties them to determining TTC. The Transmission Service Provider is responsible for providing service within the constraints established by the Transmission Operator, not actually establishing those constraints.<br><br>If an entity believes the TSP to be the appropriate entity, then options for delegation of this task exist. The Transmission Service Provider and their Transmission Operators can register as a Joint Registration Organization, with the Transmission Service Provider agreeing to take on responsibility for this requirement through written contract. If an entity does not want delegation agreements, then an entity variance or the use of a Joint Registration Organization may be appropriate. | | | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.
7. SDT posted third draft for comment from April 16–May 15, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Respond to Comments. | June 20, 2008 |
| 2. Posting for 30-day Pre-Ballot Review. | June 20, 2008 |
| 3. Initial Ballot. | July 21, 2008 |
| 4. Respond to comments. | August 20, 2008 |
| 5. Recirculation ballot. | August 21, 2008 |
| 6. 30 Day posting before board adoption. | June 21, 2008 |
| 7. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Transmission Reliability Margin Implementation Document (TRMID):** A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**

2. **Number:** **MOD-008-1**

3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.

4. **Applicability:**

   **4.1.** Transmission Operators that maintain TRM.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value:

- Aggregate Load forecast.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions ).
- Reserve sharing requirements.
- Inertial response and frequency bias.

**R1.2.** The description of the method used to allocate TRM across ATC Paths or Flowgates.

**R1.3.** The identification of the TRM calculation used for the following time periods:

**R1.3.1.** Same day and real-time.

**R1.3.2.** Day-ahead and pre-schedule.

**R1.3.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

**R2.** Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.** Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

**R4.** Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

## C. Measures

**M1.** Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, or other evidence, (such as written documentation, study reports, documentation of its CBM process, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide evidence (such as copies of emails or postal receipts that show the recipient, date and contents) that the requested documentation (such as work papers and load flow cases) was made available within the specified timeframe to the requestor. (R3)

**M4.** Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

**M5.** Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago. | The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.<br>**OR**<br>The Transmission Operator's TRMID does not address one of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3 | The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.<br>**OR**<br>The Transmission Operator's TRMID does not address two of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3 | The Transmission Operator has a TRMID that does not incorporate changes that have been made one year ago or more.<br>**OR**<br>The Transmission Operator does not have a TRMID.<br>**OR**<br>The Transmission Operator's TRMID does not address three of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3 |
| R2. | N/A | N/A | N/A | One or both of the following:<br>▪ The Transmission Operator included elements of uncertainty not defined in R1 in their establishment of TRM.<br>▪ The Transmission Operator included components of CBM in TRM. |
| R3. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days. | The Transmission Operator did not make the TRMID available for 90 days or more. |

| | | | | |
|---|---|---|---|---|
| R4 | The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (whichever is greater) were incorrect or missing. | The Transmission Operator did not establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). | The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago.<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values. | The Transmission Operator did not establish TRM<br>OR<br>The last determination of TRM was more than 18 months ago.<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing. |
| R5 | The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. Not more than 5% or 1 value (which ever is greater) were incorrect or missing. | The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 5% or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). | The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values. | The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 15% or 3 values (which ever is greater) were incorrect or missing. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.
7. SDT posted third draft for comment from April 16–May 15, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Respond to Comments. | June 20, 2008 |
| 2. Posting for 30-day Pre-Ballot Review. | June 20, 2008 |
| 3. Initial Ballot. | July 21, 2008 |
| 4. Respond to comments. | August 20, 2008 |
| 5. Recirculation ballot. | August 21, 2008 |
| 6. 30 Day posting before board adoption. | June 21, 2008 |
| 7. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Transmission Reliability Margin Implementation Document (TRMID):** A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**
2. **Number:** **MOD-008-1**
3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.
4. **Applicability:**

   **4.1.** Transmission Operators that maintain TRM.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value:

- Aggregate Load forecast.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions ~~not exceeding a 59-minute window~~).
- Reserve sharing requirements.
- Inertial response and frequency bias.

**R1.2.** The description of the method used to allocate TRM across ATC Paths or Flowgates.

**R1.3.** The identification of the TRM calculation used for the following time periods:

**R1.3.1.** Same day and real-time.

**R1.3.2.** Day-ahead and pre-schedule.

**R1.3.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

**R2.** Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.** Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

**R4.** Each Transmission Operator ~~using~~ that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** The Transmission Operator ~~using~~ that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

## C. Measures

**M1.** Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, ~~and CBMID ,~~ or other evidence, (such as written documentation, study reports, documentation of its CBM process, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide evidence (such as copies of emails or postal receipts that show the recipient, date and contents) that the requested documentation (such as work papers and load flow cases) was made available within the specified timeframe to the requestor. (R3)

**M4.** Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

**M5.** Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago. | The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.<br>**OR**<br>The Transmission Operator's TRMID does not address one of the ~~sub requirements~~following:<br>▪ ~~(~~R1.1~~,~~<br>▪ R1.2~~,~~<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3~~).~~<br>~~Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3.~~ | The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.<br>**OR**<br>The Transmission Operator's TRMID does not address two of the ~~sub requirements (R1.1, R1.2, R1.3).~~ following:<br>▪ R1.1<br>▪ R1.2<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3<br>~~Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3.~~ | The Transmission Operator has a TRMID that does not incorporate changes that have been made one year ago or more.<br>**OR**<br>The Transmission Operator does not have a TRMID~~;~~.<br>**OR**<br>The Transmission Operator's TRMID does not address three of the ~~sub requirements (R1.1, R1.2, R1.3).~~following:<br>▪ R1.1<br>▪ R1.2<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3~~Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3.~~ |
| R2. | N/A | N/A | N/A | One or both of the following:<br>▪ The Transmission Operator included elements of uncertainty not defined in R1 in their establishment of TRM. |

| | | | | |
|---|---|---|---|---|
| | | | | ~~OR~~ ▪ The Transmission Operator included components of CBM in TRM. |
| R3. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days. | The Transmission Operator did not make the TRMID available for 90 days or more. |
| R4 | The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (which ever is greater) were incorrect or missing. | The Transmission Operator did not establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). | The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago.<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values. | The Transmission Operator did not establish TRM<br>OR<br>The last determination of TRM was more than 18 months ago.<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing. |
| R5 | The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or ~~incorrect~~did not match those determined in R4. | The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or ~~incorrect~~did not match those determined in R4.~~.~~ | The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or ~~incorrect~~did not match those determined in R4. | The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or ~~incorrect~~ did not match those determined in R4. |

| | | | | |
|---|---|---|---|---|
| | Not more than 5% or 1 value (which ever is greater) were incorrect or missing. | More than 5%~~,~~ or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). | More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values. | More than 15% or 3 values (which ever is greater) were incorrect or missing. |

# Implementation Plan for Standard MOD-008-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-008-1 – Transmission Reliability Margin which describes the reliability aspects of determining and maintaining a Transmission Reliability Margin and what components of uncertainty may be considered when making that determination.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes MOD-008-0. MOD-009-0 – Procedure for Verifying Transmission Reliability Margin Values, has been incorporated into this standard, made irrelevant by this standard, or is being addressed by the North American Energy Standards Board, and should be retired when MOD-008-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-008-1 | ■ | | | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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# Implementation Plan for Standard MOD-008-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-008-1 – Transmission Reliability Margin which describes the reliability aspects of determining and maintaining a Transmission Reliability Margin and what components of uncertainty may be considered when making that determination.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes MOD-008-0. MOD-009-0 – Procedure for Verifying Transmission Reliability Margin Values, has been incorporated into this standard, made irrelevant by this standard, or is being addressed by the North American Energy Standards Board, and should be retired when MOD-008-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-008-1 | ■ | | | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Summary of Process Steps Taken Following Posting of the Standards for 30-day Comment

The ATC Standard Drafting Team is developing the ATC-related standards, in part, as a response to FERC Order 890. Order 890 provided specific guidance on the timeliness of this standards development effort. The drafting team has been working to a strict time line to ensure it can file these standards in compliance with the Commission's directives, while also adhering to the NERC Reliability Standards Development Procedure.

As described in Step 8 of NERC's Reliability Standards Development Procedure,

> "Based on the comments received and field testing, the standard drafting team may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the effect or use of the standard."

When reviewing the comments received and considering changes to the standards, the drafting team also considered that any substantive changes to the requirements would require an additional 30-day comment and response period, which would eliminate the possibility of meeting the FERC's submission deadlines. The drafting team carefully weighed the reliability benefit of any changes to the standard, and attempted to limit its modifications to those that clarify or explain, rather than create new requirements or change intent. The changes to the standards made by the drafting team fall into one or more of the following categories:

- Corrections
- Redrafting of language that does not change intent
- Clarifications that better explain intent
- Modifications that change minor details, but not intent
- Modifications to ensure consistency and reduce ambiguity

The drafting team does not believe that any of the changes made to the requirements following the last comment period directly or materially affect the effect or use of the standards, but instead make the standards more clear.

The NERC Standards Committee is a stakeholder group responsible for the oversight of standards development, including evaluation of the responses to comments and any changes to the standards. As described in Step 8 of NERC's Reliability Standards Development Procedure:

> "When the Standards Committee receives a draft standard that is recommended for ballot, the Standards Committee will review the standard and recommendations of the standards process manager to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives and requirements cited in Steps 1 to 8, as applicable; has an implementation plan; and is compatible with other existing standards. If the proposed standard does not pass this review, the Standards Committee shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the Standards

Committee shall set the proposed standard for ballot as soon as the work flow will accommodate."

NERC's Standards Process Manager presented the changes described above to the Executive Committee of the NERC Standards Committee on June 19, 2008. Following review of the revisions made to the standards, comment responses, and implementation plans, the Standards Committee's Executive Committee determined that the standards had passed the review, and the changes made do not directly or materially affect the effect or use of the standards. The Standards Committee's Executive Committee directed NERC's Standards Process Manager to post the standards for 30-day pre-ballot review and to begin assembling the ballot pools necessary for balloting.

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## Reliability Standards



| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC et al Standard - MOD-008_in |
| **Ballot Period:** | 7/21/2008 - 7/30/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 214 |
| **Total Ballot Pool:** | 227 |
| **Quorum:** | **94.27 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 80.44 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

**Summary of Ballot Results**

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 64 | 1 | 44 | 0.83 | 9 | 0.17 | 6 | 5 |
| 2 - Segment 2. | 9 | 0.8 | 8 | 0.8 | 0 | 0 | 0 | 1 |
| 3 - Segment 3. | 63 | 1 | 48 | 0.873 | 7 | 0.127 | 6 | 2 |
| 4 - Segment 4. | 13 | 1 | 6 | 0.545 | 5 | 0.455 | 2 | 0 |
| 5 - Segment 5. | 36 | 1 | 24 | 0.8 | 6 | 0.2 | 4 | 2 |
| 6 - Segment 6. | 26 | 1 | 18 | 0.783 | 5 | 0.217 | 1 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 3 | 0.2 | 1 | 0.1 | 1 | 0.1 | 1 | 0 |
| 9 - Segment 9. | 5 | 0.4 | 4 | 0.4 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.6 | 5 | 0.5 | 1 | 0.1 | 1 | 0 |
| **Totals** | **227** | **7** | **158** | **5.631** | **34** | **1.369** | **22** | **13** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Ameren Services Company | Kirit S. Shah | Negative | View |
| 1 | American Electric Power | Paul B. Johnson | Affirmative | View |
| 1 | American Transmission Company, LLC | Jason Shaver | Affirmative | |
| 1 | Arizona Public Service Co. | Cary B. Deise | Affirmative | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Basin Electric Power Cooperative | David Rudolph | Negative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | |
| 1 | Brazos Electric Power Cooperative, Inc. | Tony Kroskey | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Abstain | |
| 1 | Central Lincoln PUD | Ronald Beck | Affirmative | |
| 1 | Central Maine Power Company | Brian Conroy | | |
| | City of Tacoma, Department of Public | | | |

| | | | | |
|---|---|---|---|---|
| 1 | Utilities, Light Division, dba Tacoma Power | Alan L Cooke | Affirmative | |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | E.ON U.S. LLC | Larry Monday | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Affirmative | |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Manitoba Hydro | Michelle Rheault | Affirmative | |
| 1 | Minnesota Power, Inc. | Carol Gerou | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Abstain | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Affirmative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Affirmative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Progress Energy Carolinas | Sammy Roberts | Affirmative | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Abstain | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Abstain | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | View |
| 1 | Transmission Agency of Northern California | James W Beck | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Affirmative | View |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Western Farmers Electric Coop. | Alan Derichsweiler | | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |

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|---|---|---|---|---|
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Affirmative | |
| 2 | New Brunswick System Operator | Alden Briggs | Affirmative | |
| 2 | New York Independent System Operator | Gregory Campoli | Affirmative | |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Ameren Services Company | Mark Peters | Negative | View |
| 3 | American Electric Power | Raj Rana | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Affirmative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Blachly-Lane Electric Co-op | Bud Tracy | Affirmative | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | |
| 3 | City of McMinnville | Rick Rozanski | Abstain | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Negative | View |
| 3 | Clatskanie People's Utility District | Joseph Taffe | Affirmative | |
| 3 | Clearwater Power Co. | Dave Hagen | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Constellation Energy | Carolyn Ingersoll | Affirmative | View |
| 3 | Consumers Energy | David A. Lapinski | Abstain | |
| 3 | Coos-Curry Electric Cooperative, Inc | Roger Meader | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Affirmative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Grays Harbor PUD | Wesley W Gray | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Affirmative | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Lost River Electric Cooperative | Richard Reynolds | Affirmative | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Affirmative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Affirmative | |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | Nevada Power Co. | Sheryl Torrey | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Northern Indiana Public Service Co. | William SeDoris | Negative | |
| 3 | Northern Lights Inc. | Jon Shelby | Affirmative | |
| 3 | Northern Wasco County People's Utility District (PUD) | Paul Titus | Affirmative | |
| 3 | Okanogan County Electric Cooperative, Inc. | Ray Ellis | Affirmative | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Affirmative | |
| 3 | Progress Energy Carolinas | Sam Waters | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Abstain | |

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|---|---|---|---|---|
| 3 | Public Utility District No. 1 of Benton County | Gloria Bender | Affirmative | |
| 3 | Public Utility District No. 1 of Franklin County | Linda Boomer | Affirmative | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Affirmative | |
| 3 | Raft River Rural Electric Cooperative | Heber Carpenter | Affirmative | |
| 3 | Salmon River Electric Cooperative | Ken Dizes | Affirmative | |
| 3 | Salt River Project | John T. Underhill | Affirmative | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | | |
| 3 | Umatilla Electric Cooperative | Steve Eldrige | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | Alliant Energy Corp. Services, Inc. | Kenneth Goldsmith | Negative | View |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Affirmative | |
| 4 | Northern California Power Agency | Fred E. Young | Affirmative | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Negative | |
| 4 | Pacific Northwest Generating Cooperative | Aleka K Scott | Affirmative | |
| 4 | Public Power Council | Nancy Baker | Abstain | |
| 4 | Public Utility District No. 1 of Douglas County | Henry E. LuBean | Negative | View |
| 4 | Public Utility District No. 1 of Snohomish County | John D. Martinsen | Affirmative | |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 4 | WPS Resources Corp. | Christopher Plante | Negative | View |
| 5 | AEP Service Corp. | Brock Ondayko | Affirmative | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | |
| 5 | City of Farmington | Clinton J Jacobs | Affirmative | |
| 5 | City of Tallahassee | Alan Gale | Abstain | |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Negative | View |
| 5 | Deseret Power | Philip B Tice Jr | Affirmative | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entergy Corporation | Stanley M Jaskot | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | IBERDROLA RENEWABLES | Laura Beane | Affirmative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Affirmative | |
| 5 | New York Power Authority | Gerald Mannarino | Affirmative | |
| 5 | Orlando Utilities Commission | Richard Kinas | Abstain | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Affirmative | |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seattle City Light | Michael J. Haynes | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | | |
| 5 | Southeastern Power Administration | Douglas Spencer | Affirmative | |

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|---|---|---|---|---|
| 5 | Southern California Edison Co. | David Schiada | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Abstain | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | U.S. Bureau of Reclamation | Martin Bauer | | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Affirmative | |
| 6 | AEP Marketing | Edward P. Cox | Affirmative | View |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Negative | View |
| 6 | Dominion Resources, Inc. | Louis S Slade | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | IBERDROLA RENEWABLES | Kellie J Schreiner | Affirmative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Affirmative | |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Affirmative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Affirmative | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | Southern California Edison Co. | Marcus V Lotto | Affirmative | |
| 6 | Tampa Electric Co. | Jose Benjamin Quintas | | |
| 6 | Tenaska Power Services Co. | Cliff T Richardson | Abstain | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Affirmative | |
| 7 | Eastman Chemical Company | Lloyd Webb | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Abstain | |
| 8 | Other | Michehl R. Gent | Affirmative | |
| 8 | Volkmann Consulting | Terry Volkmann | Negative | View |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Abstain | View |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | SERC Reliability Corporation | Carter B Edge | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

609.452.8060 (Voice) - 609.452.9550 (Fax)

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| Ameren Services Company | 1 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-008-1. (1) Applicability: The Transmission Service Provider not the Transmission Operator should be responsible for TRM methodology. This is especially true when the Transmission Service Provider determines TRM for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO. (2) Is TRM a reliability parameter or a market parameter? While the concepts of uncertainty and sensitivity analysis are inherent in reliability planning TRM as a metric has not been previously defined in the planning process. TRM has been applied in sale of open access transmission system to limit exposure to oversubscription of transmission service. As such TRM should be the responsibility of the Transmission Service Provider. (3) That said we are aware that the oversubscription of transmission service can lead to reliability problems. (4) The Transmission Service Provider, Transmission Operator, Planning Coordinator, and Transmission Planner should coordinate and cooperate in developing the TRM methodology. (5)TRM is applicable in the Operating Time Horizon and the one-year and beyond horizon. |
| American Electric Power | 1 | Affirmative | AEP votes affirmative, but we have a concern that the standard appears to have an internal ambiguity. The applicability states “Transmission Operators that maintain TRM" however, R1 requires that “Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) ...." In the context of R1, it unclear what requirements are placed upon Transmission Operators that DOES NOT maintain TRM. In addition, the Purpose statement implies that TRM is used as a real-time operation value. It is not. Despite these reservations, the proposed standard is benign, and AEP does vote affirmative. |
| Brazos Electric Power Cooperative, Inc. | 1 | Negative | A NEGATIVE vote is cast for this standard as written as it imposes obligations on entities in the ERCOT region that do not utilize ATC paths and calculation methodologies to manage congestion or for reliability operations. Our previous submitted comments suggested that applicability language be included in the requirements to recognize that such market difference exists. |
| Exelon Energy | 1 | Affirmative | General comment These standards bring the industry closer to a unified ATC calculation methodology by requiring that one of three calculation methodologies be utilized and documented. This is an improvement from where the industry is today but falls short of FERC Order No. 890. The standards still lack a requirement for ATC or AFC calculations to be consistent with criteria used in operating and planning studies for corresponding time periods. Exelon's comments reflect these deficiencies and Exelon will be making these same points to FERC if these standards are approved, requesting that the FERC direct NERC to approve the standards but modify the standards to be consistent with Order No. 890. Suggested modifications to the standards to achieve this consistency are included in our comments. MOD-008-1 TRM Calculation Methodology Standard lacks a requirement that components of TRM be consistent with those used in operating and planning studies for the same time period being studied |
| FirstEnergy Energy Delivery | 1 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-008 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| | | | classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-008 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-008 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - All Requirements (R1 through R5) Additional Comments: Applicability Section - The applicability states "Transmission Operators that maintain TRM" and all requirements of the standard are applicable to the TOP in regards to preparing and maintaining a TRM Implementation Document (TRMID), distributing the TRMID to other interested parties, calculating TRM consistent with the TRMID, etc. It is unclear to FE what requirements are placed upon a Transmission Operator that DOES NOT maintain TRM. A TOP who does not maintain TRM could be interpreted one of two ways: 1) For a given TOP footprint TRM is not withheld in calculating ATC 2) TRM is withheld for the TOP footprint, but the TOP does not determine or calculate the TRM value withheld. If the appropriate interpretation is as described in item 1) above, it begs the question if this is a needed reliability standard. If TRM is truly a reliability need, it can not be optional for any TOP service area. If the latter, item 2 and FE's understanding, is the correct interpretation, then FE's position on responsibility remains that that the applicability of this standard should rest with the entity performing the calculation of TRM which in many areas of the country is the TSP organization. Since the SDT has elected to not make a change in this regard we are requesting the aforementioned variance for the MISO RTO area. |
| Great River Energy | 1 | Negative | GRE is concerned with the Transmission Operator being the responsible entity for MOD-008. GRE believes that the responsible entity for these requirements should be the Transmission Service Provider. If the Transmission Operator does not perform this function then a delegation agreement must be created between it and the entity performing the function. It is GRE's opinion that a standard should not knowingly be written in a manner that requires delegation agreements for a large number of responsible entities, doing so is an inefficient use of resources. |
| Sierra Pacific Power Co. | 1 | Affirmative | Affirmative vote with comment: The severity levels surrounding R1 still appear to imply that all of the sub-items of R1.1 are expected to be used in the TRMID. It must be clear that it does not constitute a violation if |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| | | | various of these sub-items are not applicable to the TRMID used by the entity. Clarify that this is "as applicable" or "as determined by the entity". |
| Southwest Transmission Cooperative, Inc. | 1 | Affirmative | SWTC supports all elements of MOD-08; however, the VSLs as redrafted to accommodate the industry comments have blurred the lines of severity and grant additional discretion to the enforcement entity. Further, the Applicable entity should be clarified throughout the standard to clearly identify whether the standard applies only to TOs that maintain TRM or to all TOs. |
| Tucson Electric Power Co. | 1 | Affirmative | TEP supports proposed WECC Team remedial language clarifying VSL severity level. |
| Ameren Services Company | 3 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-008-1. Applicability: The Transmission Service Provider not the Transmission Operator should be responsible for TRM methodology. This is especially true when the Transmission Service Provider determines TRM for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO. Is TRM a reliability parameter or a market parameter? While the concepts of uncertainty and sensitivity analysis are inherent in reliability planning TRM as a metric has not been previously defined in the planning process. TRM has been applied in sale of open access transmission system to limit exposure to oversubscription of transmission service. As such TRM should be the responsibility of the Transmission Service Provider. That said we are aware that the oversubscription of transmission service can lead to reliability problems. The Transmission Service Provider, Transmission Operator, Planning Coordinator, and Transmission Planner should coordinate and cooperate in developing the TRM methodology. TRM is applicable in the Operating Time Horizon and the one-year and beyond horizon |
| City Public Service of San Antonio | 3 | Negative | I cannot vote for this standard as written. It needs to acknowledge definitive alternatives to ATC for regions or markets such as ERCOT where transmission service markets are not used. |
| Constellation Energy | 3 | Affirmative | Greater standardization in the determination of TRM and monitoring of the on-going appropriateness of the amount set aside for TRM is required. |
| FirstEnergy Solutions | 3 | Affirmative | FirstEnergy Corp. appreciates the hard work of the Standard Drafting Team on the challenging task of reorganizing and enhancing the verbiage of the IROL requirements. We vote AFFIRMATIVE to standard IRO-008-1 and ask that the SDT consider our enclosed comments. Comments on EOP-001, IRO-002, IRO-004, IRO-005, TOP-003, TOP-005, and TOP-006: General “The Violation Risk Factors should be added to the text of all of the standards. IRO-004 - VSL table shows “R7” instead of “R1” IRO-005 - Several Measures reference the incorrect requirement numbers TOP-003 - R4 — There is no measure associated with this requirement - Measures do not include evidence of “planning” of scheduled outages per the requirements - VSL for R3 and R4 are incorrect and reference the wrong entity per the requirements |
| Lincoln Electric System | 3 | Negative | LES is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| Wisconsin Public Service Corp. | 3 | Negative | The Transmission Service Provider should be the responsible entity for MOD-008, not the Transmission Operator. |
| Alliant Energy Corp. Services, | 4 | Negative | We believe the Transmission Service Provider should be the responsible entity. |

| Entity | Segment | Vote | Comment |
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| Inc. | | | |
| Public Utility District No. 1 of Douglas County | 4 | Negative | We have not had sufficient time to review the effects of this change and coordinate it with others in our region. |
| WPS Resources Corp. | 4 | Negative | Requirement R3. The TRMID document should be made available to all users, owners, and operators. That is, the TRMID should be publicly available. |
| Constellation Generation Group | 5 | Negative | Greater standardization in the determination of TRM and monitoring of the on-going appropriateness of the amount set aside for TRM is required then this standard provides. TRM seems to be applied only at certain times by certain TPs. For example, one large TP in the South applies TRM only when an entity is looking for long term transmission service outside an 18 month window. That is, if the transmission service is for a year but the year begins and ends within the next 18 months, TRM isn't applied. This causes a very significant difference in study results. Others apply it differently. This type of item should be standardized. |
| Electric Power Supply Association | 5 | Negative | Greater standardization is required with the standard as drafted. Determination of TRM and monitoring of the associated with the ongoing appropriateness of the amounts set aside for TRM is required to achieve the needed standardization. |
| FirstEnergy Solutions | 5 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-008 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-008 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-008 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - All Requirements (R1 through R5) Additional Comments: Applicability Section - The applicability states "Transmission Operators that maintain TRM" and all requirements of the standard are applicable to the TOP in regards to preparing |

| Entity | Segment | Vote | Comment |
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| | | | and maintaining a TRM Implementation Document (TRMID), distributing the TRMID to other interested parties, calculating TRM consistent with the TRMID, etc. It is unclear to FE what requirements are placed upon a Transmission Operator that DOES NOT maintain TRM. A TOP who does not maintain TRM could be interpreted one of two ways: 1) For a given TOP footprint TRM is not withheld in calculating ATC 2) TRM is withheld for the TOP footprint, but the TOP does not determine or calculate the TRM value withheld. If the appropriate interpretation is as described in item 1) above, it begs the question if this is a needed reliability standard. If TRM is truly a reliability need, it can not be optional for any TOP service area. If the latter, item 2 and FE's understanding, is the correct interpretation, then FE's position on responsibility remains that that the applicability of this standard should rest with the entity performing the calculation of TRM which in many areas of the country is the TSP organization. Since the SDT has elected to not make a change in this regard we are requesting the aforementioned variance for the MISO RTO area. |
| Lincoln Electric System | 5 | Negative | LES is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| AEP Marketing | 6 | Affirmative | AEP has a concern because the standard appears to have an internal ambiguity. The applicability states "Transmission Operators that maintain TRM" however, R1 requires that "Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) ...." In the context of R1, it unclear what requirements are placed upon Transmission Operators that DOES NOT maintain TRM. In addition, the Purpose statement implies that TRM is used as a real-time operation value. It is not. |
| Barry Green Consulting Inc. | 6 | Negative | Greater standardization in the determination of TRM and monitoring of the on-going appropriateness of the amount set aside for TRM is required. |
| Constellation Energy Commodities Group | 6 | Negative | Greater standardization in the determination of TRM and monitoring of the ongoing appropriateness of the amount set aside for TRM is required. |
| FirstEnergy Solutions | 6 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-008 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-008 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial |

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|---|---|---|---|
| | | | development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, “Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance.” FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-008 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - All Requirements (R1 through R5) Additional Comments: Applicability Section - The applicability states “Transmission Operators that maintain TRM” and all requirements of the standard are applicable to the TOP in regards to preparing and maintaining a TRM Implementation Document (TRMID), distributing the TRMID to other interested parties, calculating TRM consistent with the TRMID, etc. It is unclear to FE what requirements are placed upon a Transmission Operator that DOES NOT maintain TRM. A TOP who does not maintain TRM could be interpreted one of two ways: 1) For a given TOP footprint TRM is not withheld in calculating ATC 2) TRM is withheld for the TOP footprint, but the TOP does not determine or calculate the TRM value withheld. If the appropriate interpretation is as described in item 1) above, it begs the question if this is a needed reliability standard. If TRM is truly a reliability need, it can not be optional for any TOP service area. If the latter, item 2 and FE’s understanding, is the correct interpretation, then FE’s position on responsibility remains that that the applicability of this standard should rest with the entity performing the calculation of TRM which in many areas of the country is the TSP organization. Since the SDT has elected to not make a change in this regard we are requesting the aforementioned variance for the MISO RTO area. |
| Lincoln Electric System | 6 | Negative | LES is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| Volkmann Consulting | 8 | Negative | This standard does not show the applicability to the Transmission Service Provider. In RTOs the TSP is responsible for calculating and maintaining TRM. Delegation agreements can cover this. However, with the larger portion of the Eastern Interconnection covered by regional tariffs and TSP operation, this standard should speak directly to the TSP responsibilities |
| Electric Reliability Council of Texas, Inc. | 10 | Abstain | Although the Applicability Section is clear, some Requirements and Measures contain no clear applicability only to those Transmission Operators that maintain TRM in their transmission system and market operations. |
| Midwest Reliability Organization | 10 | Negative | The MRO is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |

# Consideration of Comments on Initial Ballot — MOD-008-1 — Transmission Reliability Margin Calculation Methodology

**Summary Consideration:** While some stakeholders suggested modifications to the standard, most stakeholders agreed with the standard as proposed and the drafting team did not make any changes to the standard.

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| Ameren Services Company | 1 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-008-1.<br><br>(1) Applicability: The Transmission Service Provider not the Transmission Operator should be responsible for TRM methodology. This is especially true when the Transmission Service Provider determines TRM for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO.<br><br>(2) Is TRM a reliability parameter or a market parameter? While the concepts of uncertainty and sensitivity analysis are inherent in reliability planning TRM as a metric has not been previously defined in the planning process. TRM has been applied in sale of open access transmission system to limit exposure to oversubscription of transmission service. As such TRM should be the responsibility of the Transmission Service Provider.<br><br>(3) That said we are aware that the oversubscription of transmission service can lead to reliability problems.<br><br>(4) The Transmission Service Provider, Transmission Operator, Planning Coordinator, and Transmission Planner should coordinate and cooperate in developing the TRM methodology.<br>(5)TRM is applicable in the Operating Time Horizon and the one-year and beyond horizon. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structure; however, we are required to pick a single entity as responsible for this task.<br><br>The SDT believes TRM is a reliability parameter, as the Transmission Operator may expect it to be available as one of its tools to manage the reliability of the system and respond to situations outside expected conditions. | | | |

<table>
<tr><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="4">The SDT concurs that oversubscription can lead to reliability problems.<br><br>Developing requirements that require collaboration are difficult, as it can be challenging to discover who is not complying. For example, if MISO and Ameren were unable to come to agreement on development of a TRM methodology, should both entities be sanctioned for not meeting the TRM requirements? NERC has attempted to address this through allowing the use of Joint Registration Organizations, where a MISO/Ameren collaboration would be sanctioned as a single entity, and then the JRO would be responsible for determining how to allocate those sanctions among participants in the JRO.<br><br>With regard to the Time Horizons used in compliance (which are generally used to indicate how much time is available for mitigating a violation to the requirements), the SDT believes the correct horizon is Operations Planning.</td></tr>
<tr><td>American Electric Power</td><td>1</td><td>Affirmative</td><td>AEP votes affirmative, but we have a concern that the standard appears to have an internal ambiguity. The applicability states “Transmission Operators that maintain TRM" however, R1 requires that “Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) ...." In the context of R1, it unclear what requirements are placed upon Transmission Operators that DOES NOT maintain TRM. In addition, the Purpose statement implies that TRM is used as a real-time operation value. It is not. Despite these reservations, the proposed standard is benign, and AEP does vote affirmative.</td></tr>
<tr><td colspan="4">Response: The entire standard only applies to those Transmission Operators that maintain TRM and because this is specified in the applicability, the standard did not reiterate this in the requirements. With regard to the use of TRM as a real-time operation value, the SDT believes that while the TRM may not be explicitly scheduled, the capacity withheld as a margin may be used in real-time (e.g., if load forecast is higher than expected, then some of the margin may be used to support the additional internal generation needed to serve that load).</td></tr>
<tr><td>Brazos Electric Power Cooperative, Inc.</td><td>1</td><td>Negative</td><td>A NEGATIVE vote is cast for this standard as written as it imposes obligations on entities in the ERCOT region that do not utilize ATC paths and calculation methodologies to manage congestion or for reliability operations. Our previous submitted comments suggested that applicability language be included in the requirements to recognize that such market difference exists.</td></tr>
<tr><td colspan="4">Response: If ERCOT does not utilize TRM, then this standard does not apply.</td></tr>
<tr><td>Exelon Energy</td><td>1</td><td>Affirmative</td><td>General comment These standards bring the industry closer to a unified ATC calculation methodology by requiring that one of three calculation methodologies be utilized and documented. This is an improvement from where the industry is today but falls short of FERC Order No. 890. The standards still lack a requirement for ATC or AFC calculations to be consistent with criteria used in operating and planning studies for corresponding time periods. Exelon's comments reflect these deficiencies and Exelon will be making these same points to FERC if these standards are approved, requesting that the FERC direct NERC to approve the standards but modify the standards to be consistent with Order No. 890. Suggested modifications to the standards to achieve this consistency are included in our comments. MOD-008-1 TRM Calculation Methodology Standard lacks a requirement that</td></tr>
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| Entity | Segment | Vote | Comment |
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| | | | components of TRM be consistent with those used in operating and planning studies for the same time period being studied |
| **Response**: The SDT considered adding the requirement described in previous discussions. However, to do so would negate the value of TRM, as TRM is specifically intended to be based on situations other than those expected. For example, the system might be expected to operate with a load of 10,000 MW. TRM is intended to be used to create a margin such that if load is 11,000 MW, transmission capacity is available to support the serving of that load. In this example, the operations studies performed might include an 11,000 MW case, but would not necessarily include an explicit TRM. The SDT does not believe this to be inconsistent with the intent of Order 890. | | | |
| FirstEnergy Energy Delivery | 1 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-008 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-008 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-008 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - All Requirements (R1 through R5) Additional Comments: Applicability Section - The applicability states "Transmission Operators that maintain TRM" and all requirements of the standard are applicable to the TOP in regards to preparing and maintaining a TRM Implementation Document (TRMID), distributing the TRMID to other interested parties, calculating TRM |

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| | | | consistent with the TRMID, etc. It is unclear to FE what requirements are placed upon a Transmission Operator that DOES NOT maintain TRM. A TOP who does not maintain TRM could be interpreted one of two ways: 1) For a given TOP footprint TRM is not withheld in calculating ATC 2) TRM is withheld for the TOP footprint, but the TOP does not determine or calculate the TRM value withheld. If the appropriate interpretation is as described in item 1) above, it begs the question if this is a needed reliability standard. If TRM is truly a reliability need, it can not be optional for any TOP service area. If the latter, item 2 and FE's understanding, is the correct interpretation, then FE's position on responsibility remains that that the applicability of this standard should rest with the entity performing the calculation of TRM which in many areas of the country is the TSP organization. Since the SDT has elected to not make a change in this regard we are requesting the aforementioned variance for the MISO RTO area. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. The SDT believes the transfer of responsibility described within the MISO Transmission Owners Agreement would be an effective way to delegate this task to a Transmission Service Provider through the registration of a Joint Registration Organization. To the extent an entity variance is desired, First Energy and/or MISO would need to submit a SAR to request the variance. The commenter is correct that ideally a variance would be considered in the SAR process and throughout the standard development process; however, no one has yet requested a variance through a SAR (or incorporated the request into one of the existing SARs during their development), and at this time the drafting team can not add a variance and still meet the deadline established by NERC and FERC for this revision of the standard.<br><br>Regarding the applicability of the standard, the entire standard only applies to those Transmission Operators that operate their system with the assumption that some transmission capacity margin has been withheld from commercial use to address the reliability threats listed in R1. The SDT does not believe that TRM is required for all entities; entities that have reviewed the risks listed in R1 and determined that they can manage those risks through other means (e.g., demand **Response**, operating guides, etc...) are not required to maintain TRM. | | | |
| Great River Energy | 1 | Negative | GRE is concerned with the Transmission Operator being the responsible entity for MOD-008. GRE believes that the responsible entity for these requirements should be the Transmission Service Provider. If the Transmission Operator does not perform this function then a delegation agreement must be created between it and the entity performing the function. It is GRE's opinion that a standard should not knowingly be written in a manner that requires delegation agreements for a large number of responsible entities, doing so is an inefficient use of resources. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; | | | |

| Entity | Segment | Vote | Comment |
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| however, we are required to pick a single entity as responsible for this task. | | | |
| Sierra Pacific Power Co. | 1 | Affirmative | Affirmative vote with comment: The severity levels surrounding R1 still appear to imply that all of the sub-items of R1.1 are expected to be used in the TRMID. It must be clear that it does not constitute a violation if various of these sub-items are not applicable to the TRMID used by the entity. Clarify that this is "as applicable" or "as determined by the entity". |
| **Response**: The VSL indicates that entities must comply with R1.1. R1.1 requires the "Identification of… each of the following components of uncertainty *if used in establishing TRM*" (emphasis added). If the entity does not use a specific element in determining TRM, then its absence would not result in a violation. | | | |
| Southwest Transmission Cooperative, Inc. | 1 | Affirmative | SWTC supports all elements of MOD-08; however, the VSLs as redrafted to accommodate the industry comments have blurred the lines of severity and grant additional discretion to the enforcement entity. Further, the Applicable entity should be clarified throughout the standard to clearly identify whether the standard applies only to TOs that maintain TRM or to all TOs. |
| **Response**: The SDT reviewed the VSLs and concludes that they appropriately minimize the discretion of the enforcement entity. If in future comments on standards you could be more specific, that would aid the team in addressing your concerns.<br><br>The entire standard only applies to those Transmission Operators that maintain TRM and because this is specified in the applicability, the standard did not reiterate this in the requirements. | | | |
| Tucson Electric Power Co. | 1 | Affirmative | TEP supports proposed WECC Team remedial language clarifying VSL severity level. |
| **Response**: The SDT does not have the WECC team remedial language, and therefore cannot comment on it. | | | |
| Ameren Services Company | 3 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-008-1.<br>Applicability: The Transmission Service Provider not the Transmission Operator should be responsible for TRM methodology. This is especially true when the Transmission Service Provider determines TRM for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO.<br><br>Is TRM a reliability parameter or a market parameter? While the concepts of uncertainty and sensitivity analysis are inherent in reliability planning TRM as a metric has not been previously defined in the planning process. TRM has been applied in sale of open access transmission system to limit exposure to oversubscription of transmission service. As such TRM should be the responsibility of the Transmission Service Provider. That said we are aware that the oversubscription of transmission service can lead to reliability problems.<br><br>The Transmission Service Provider, Transmission Operator, Planning Coordinator, and Transmission Planner should coordinate and cooperate in developing the TRM methodology. |

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<tr><td>City Public Service of San Antonio</td><td>3</td><td>Negative</td><td>I cannot vote for this standard as written. It needs to acknowledge definitive alternatives to ATC for regions or markets such as ERCOT where transmission service markets are not used.</td></tr>
<tr><td colspan="4">Response: If ERCOT does not utilize TRM, then this standard does not apply.</td></tr>
<tr><td>Constellation Energy</td><td>3</td><td>Affirmative</td><td>Greater standardization in the determination of TRM and monitoring of the on-going appropriateness of the amount set aside for TRM is required.</td></tr>
<tr><td colspan="4">Response: The SDT did not believe that it could, at this time, define a single methodology for TRM without arbitrarily affecting either reliability, market access or both. The SDT encourages entities to submit requests for future work to be considered as part of NERC’s annual standards planning process.</td></tr>
<tr><td>FirstEnergy Solutions</td><td>3</td><td>Affirmative</td><td>FirstEnergy Corp. appreciates the hard work of the Standard Drafting Team on the challenging task of reorganizing and enhancing the verbiage of the IROL requirements. We vote AFFIRMATIVE to standard IRO-008-1 and ask that the SDT consider our enclosed comments. Comments on EOP-001, IRO-002, IRO-004, IRO-005, TOP-003, TOP-005, and TOP-006: General “The Violation Risk Factors should be added to the text of all of the standards. IRO-004 - VSL table shows “R7” instead of “R1” IRO-005 - Several Measures reference the incorrect requirement numbers TOP-003 - R4 — There is no measure associated with this requirement - Measures do not include evidence of “planning” of</td></tr>
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<tr><td></td><td></td><td></td><td>scheduled outages per the requirements - VSL for R3 and R4 are incorrect and reference the wrong entity per the requirements</td></tr>
<tr><td colspan="4">Response: The SDT does not believe these comments are related to MOD-008.</td></tr>
<tr><td>Lincoln Electric System</td><td>3</td><td>Negative</td><td>LES is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission Service Provider.</td></tr>
<tr><td colspan="4">Response: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task.</td></tr>
<tr><td>Wisconsin Public Service Corp.</td><td>3</td><td>Negative</td><td>The Transmission Service Provider should be the responsible entity for MOD-008, not the Transmission Operator.</td></tr>
<tr><td colspan="4">Response: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task.</td></tr>
<tr><td>Alliant Energy Corp. Services, Inc.</td><td>4</td><td>Negative</td><td>We believe the Transmission Service Provider should be the responsible entity.</td></tr>
<tr><td colspan="4">Response: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task.</td></tr>
<tr><td>Public Utility District No. 1 of Douglas County</td><td>4</td><td>Negative</td><td>We have not had sufficient time to review the effects of this change and coordinate it with others in our region.</td></tr>
<tr><td colspan="4">Response: The SDT believes that significant time has been allowed for entities to review and comment on the standard.</td></tr>
<tr><td>WPS Resources Corp.</td><td>4</td><td>Negative</td><td>Requirement R3. The TRMID document should be made available to all users, owners, and operators. That is, the TRMID should be publicly available.</td></tr>
<tr><td colspan="4">Response: The North American Energy Standards Board (NAESB) is responsible for developing business practices related to public availability of information to support commercial needs. The SDT believes it is NAESB intention to require the disclosure of the TRMID on the OASIS. The NERC standard is related only to reliability, and there is no reliability need for public posting.</td></tr>
<tr><td>Constellation Generation Group</td><td>5</td><td>Negative</td><td>Greater standardization in the determination of TRM and monitoring of the on-going appropriateness of the amount set aside for TRM is required then this standard provides.</td></tr>
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| | | | TRM seems to be applied only at certain times by certain TPs. For example, one large TP in the South applies TRM only when an entity is looking for long term transmission service outside an 18 month window. That is, if the transmission service is for a year but the year begins and ends within the next 18 months, TRM isn't applied. This causes a very significant difference in study results. Others apply it differently. This type of item should be standardized. |
| **Response**: The SDT did not believe that it could, at this time, define a single methodology for TRM without arbitrarily affecting either reliability, market access or both. The SDT encourages entities to submit requests for future work to be considered as part of NERC's annual planning process. The MOD standards do require that TRM and other factors of TTC/TFC be applied consistently by an entity so that all users of their system are treated equally. | | | |
| Electric Power Supply Association | 5 | Negative | Greater standardization is required with the standard as drafted. Determination of TRM and monitoring of the associated with the ongoing appropriateness of the amounts set aside for TRM is required to achieve the needed standardization. |
| **Response**: The SDT did not believe that it could, at this time, define a single methodology for TRM without arbitrarily affecting either reliability, market access or both. The SDT encourages entities to submit requests for future work to be considered as part of NERC's annual planning process. | | | |
| FirstEnergy Solutions | 5 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-008 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-008 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| | | | to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-008 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - All Requirements (R1 through R5) Additional Comments: Applicability Section - The applicability states "Transmission Operators that maintain TRM" and all requirements of the standard are applicable to the TOP in regards to preparing and maintaining a TRM Implementation Document (TRMID), distributing the TRMID to other interested parties, calculating TRM consistent with the TRMID, etc. It is unclear to FE what requirements are placed upon a Transmission Operator that DOES NOT maintain TRM. A TOP who does not maintain TRM could be interpreted one of two ways: 1) For a given TOP footprint TRM is not withheld in calculating ATC 2) TRM is withheld for the TOP footprint, but the TOP does not determine or calculate the TRM value withheld. If the appropriate interpretation is as described in item 1) above, it begs the question if this is a needed reliability standard. If TRM is truly a reliability need, it can not be optional for any TOP service area. If the latter, item 2 and FE's understanding, is the correct interpretation, then FE's position on responsibility remains that that the applicability of this standard should rest with the entity performing the calculation of TRM which in many areas of the country is the TSP organization. Since the SDT has elected to not make a change in this regard we are requesting the aforementioned variance for the MISO RTO area. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. The SDT believes the transfer of responsibility described within the MISO Transmission Owners Agreement would be an effective way to delegate this task to a Transmission Service Provider through the registration of a Joint Registration Organization. To the extent an entity variance is desired, First Energy and/or MISO would need to submit a SAR to request the variance. The commenter is correct that ideally a variance would be considered in the SAR process and throughout the standard development process; however, no one has yet requested a variance through a SAR (or incorporated the request into one of the existing SARs during their development), and at this time the drafting team can not add a variance and still meet the deadline established by NERC and FERC for this revision of the standard.<br><br>Regarding the applicability of the standard, the entire standard only applies to those Transmission Operators that operate their system with the assumption that some transmission capacity margin has been withheld from commercial use to address the reliability threats listed in R1. The SDT does not believe that TRM is required for all entities; entities that have reviewed the risks listed in R1 and determined that they can manage those risks through other means (e.g., demand response, operating guides, etc…) are not required to maintain TRM. | | | |
| Lincoln Electric System | 5 | Negative | LES is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| | | | Service Provider. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task. | | | |
| AEP Marketing | 6 | Affirmative | AEP has a concern because the standard appears to have an internal ambiguity. The applicability states “Transmission Operators that maintain TRM" however, R1 requires that “Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) ...." In the context of R1, it unclear what requirements are placed upon Transmission Operators that DOES NOT maintain TRM. In addition, the Purpose statement implies that TRM is used as a real-time operation value. It is not. |
| **Response**: The entire standard only applies to those Transmission Operators that maintain TRM and because this is specified in the applicability, the standard did not reiterate this in the requirements. With regard to the use of TRM as a real-time operation value, the SDT believes that while the TRM may not be explicitly scheduled, the capacity withheld as a margin may be used in real-time (e.g., if load forecast is higher than expected, then some of the margin may be used to support the additional internal generation needed to serve that load). | | | |
| Barry Green Consulting Inc. | 6 | Negative | Greater standardization in the determination of TRM and monitoring of the on-going appropriateness of the amount set aside for TRM is required. |
| **Response**: The SDT did not believe that it could, at this time, define a single methodology for TRM without arbitrarily affecting either reliability, market access or both. The SDT encourages entities to submit requests for future work to be considered as part of NERC's annual planning process. | | | |
| Constellation Energy Commodities Group | 6 | Negative | Greater standardization in the determination of TRM and monitoring of the ongoing appropriateness of the amount set aside for TRM is required. |
| **Response**: The SDT did not believe that it could, at this time, define a single methodology for TRM without arbitrarily affecting either reliability, market access or both. The SDT encourages entities to submit requests for future work to be considered as part of NERC's annual planning process. | | | |
| FirstEnergy Solutions | 6 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-008 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| | | | to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-008 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-008 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - All Requirements (R1 through R5) Additional Comments: Applicability Section - The applicability states "Transmission Operators that maintain TRM" and all requirements of the standard are applicable to the TOP in regards to preparing and maintaining a TRM Implementation Document (TRMID), distributing the TRMID to other interested parties, calculating TRM consistent with the TRMID, etc. It is unclear to FE what requirements are placed upon a Transmission Operator that DOES NOT maintain TRM. A TOP who does not maintain TRM could be interpreted one of two ways: 1) For a given TOP footprint TRM is not withheld in calculating ATC 2) TRM is withheld for the TOP footprint, but the TOP does not determine or calculate the TRM value withheld. If the appropriate interpretation is as described in item 1) above, it begs the question if this is a needed reliability standard. If TRM is truly a reliability need, it can not be optional for any TOP service area. If the latter, item 2 and FE's understanding, is the correct interpretation, then FE's position on responsibility remains that that the applicability of this standard should rest with the entity performing the calculation of TRM which in many areas of the country is the TSP organization. Since the SDT has elected to not make a change in this regard we are requesting the aforementioned variance for the MISO RTO area. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. The SDT believes the transfer of responsibility described within the MISO Transmission Owners Agreement would be an effective way to delegate this task to a Transmission Service Provider through the | | | |

| Entity | Segment | Vote | Comment |
|---|---|---|---|
| registration of a Joint Registration Organization. To the extent an entity variance is desired, First Energy and/or MISO would need to submit a SAR to request the variance. The commenter is correct that ideally a variance would be considered in the SAR process and throughout the standard development process; however, no one has yet requested a variance through a SAR (or incorporated the request into one of the existing SARs during their development), and at this time the drafting team can not add a variance and still meet the deadline established by NERC and FERC for this revision of the standard.<br><br>Regarding the applicability of the standard, the entire standard only applies to those Transmission Operators that operate their system with the assumption that some transmission capacity margin has been withheld from commercial use to address the reliability threats listed in R1. The SDT does not believe that TRM is required for all entities; entities that have reviewed the risks listed in R1 and determined that they can manage those risks through other means (e.g., demand response, operating guides, etc…) are not required to maintain TRM. | | | |
| Lincoln Electric System | 6 | Negative | LES is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. | | | |
| Volkmann Consulting | 8 | Negative | This standard does not show the applicability to the Transmission Service Provider. In RTOs the TSP is responsible for calculating and maintaining TRM. Delegation agreements can cover this. However, with the larger portion of the Eastern Interconnection covered by regional tariffs and TSP operation, this standard should speak directly to the TSP responsibilities |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task. | | | |
| Electric Reliability Council of Texas, Inc. | 10 | Abstain | Although the Applicability Section is clear, some Requirements and Measures contain no clear applicability only to those Transmission Operators that maintain TRM in their transmission system and market operations. |
| **Response**: The entire standard only applies to those Transmission Operators that maintain TRM and because this is specified in the applicability, the standard did not reiterate this in the requirements. | | | |
| Midwest Reliability Organization | 10 | Negative | The MRO is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task. | | | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC Authorized posting TTC/ATC/AFC SAR Development June 20 2005.
2. SAC Authorized the SAR to be developed as a standard on February 14 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from February 15–March 16, 2007.
5. SDT posted second draft for comment from May 25–June 25, 2007.
6. SDT posted third draft for comment from October 31–December 15, 2007.
7. SC conducted an Initial Ballot of the standard from March 3–12, 2008.
8. SDT posted fourth draft for comment form April 16–May 15, 2008.

**Description of Current Draft:**

This is the fifth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Respond to Comments. | June 20, 2008 |
| 2. Posting for 30-day Pre-Ballot Review. | June 20, 2008 |
| 3. Initial Ballot. | July 21, 2008 |
| 4. Respond to comments. | August 20, 2008 |
| 5. Recirculation ballot. | August 21, 2008 |
| 6. 30-day posting before board adoption. | June 21, 2008 |
| 7. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**ATC Path:** Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[1].

**Available Transfer Capability (ATC):** A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.

**Available Transfer Capability Implementation Document (ATCID):** A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.

**Transmission Operator Area:** The collection of Transmission assets over which the Transmission Operator is responsible for operating.

**Existing Transmission Commitments (ETC):** Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

**Planning Coordinator:** See Planning Authority.

**Postback:** Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

**Business Practices:** Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices**.**

**Block Dispatch:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

**Dispatch Order:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

**Participation Factors:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

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[1] See 18 CFR 37.6(b)(1)

## A. Introduction

1. **Title:** **Available Transmission System Capability**
2. **Number:** **MOD-001-1**
3. **Purpose:** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors
4. **Applicability:**
   - **4.1.** Transmission Service Provider.
   - **4.2.** Transmission Operator.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** Each Transmission Operator shall select one of the methodologies[2] listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- The Area Interchange Methodology, as described in MOD-028
- The Rated System Path Methodology, as described in MOD-029
- The Flowgate Methodology, as described in MOD-030

**R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Lower* [*Time Horizon: Operations Planning*]

**R2.1.** Hourly values for at least the next 48 hours.

**R2.2.** Daily values for at least the next 31 calendar days.

**R2.3.** Monthly values for at least the next 12 months (months 2-13).

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows including:

**R3.2.1.** How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

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[2] All ATC Paths do not have to use the same methodology and no particular ATC Path must use the same methodology for all time periods.

**R3.2.2.** A rationale for that accounting specified in R3.2.

**R3.3.** The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC or AFC.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.

**R3.5.** A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

**R3.6.** A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:

**R3.6.1.** The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.

**R3.6.2.** The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.

**R3.6.3.** How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.

**R4.** The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

**R4.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

**R4.3.** Each Transmission Operator associated with the Transmission Service Provider's area.

**R4.4.** Each Planning Coordinator adjacent to the Transmission Service Provider's area.

**R4.5.** Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

**R4.6.** Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

**R5.** The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.** When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.** When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.

**R8.2.** Daily values, once per day.

**R8.3.** Monthly values, once per week.

**R9.** Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor's ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

> Note that the North American Energy Standards Board (NAESB) is developing the companion standards that address the posting of ATC information, including supporting information such as that described in R9.

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.

- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

**R9.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

**R9.1.1.** If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available

**R9.1.2.** If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available

**R9.1.3.** If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available

**R9.2.** This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one of the specified methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator's operating area. (R1).

**M2.** The Transmission Service Provider shall provide ATC or AFC values and identification of the selected methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 48 hours of hourly values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily values calculated at all times. (R2.2)

- There has been at least the next 12 months of monthly values calculated at all times (Months 2-13). (R2.3)

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** The Transmission Service Provider shall provide evidence (such as dated electronic mail messages, mail receipts, or voice recordings) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

**M5.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

**M6.** The Transmission Operator shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate TTC or TFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC or TFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

**M7.** The Transmission Service Provider shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

**M8.** The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly values on at least the minimum frequencies specified in R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R8)

**M9.** The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R9. (R9)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

**1.3. Data Retention**

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Operator did not select one of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. |
| R2. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours.<br>▪ Has calculated daily ATC or AFC values for more than the next 21 calendar days but less than the next 31 calendar days.<br>▪ Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours.<br>▪ Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days.<br>▪ Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 21 hours.<br>▪ Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days.<br>▪ Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for less than the next 11 hours.<br>▪ Has calculated daily ATC or AFC values for less than the next 8 calendar days.<br>▪ Has calculated monthly ATC or AFC values for less than the next 4 months.<br>▪ Did not use the selected methodology(ies) to calculate ATC. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>**OR**<br>The Transmission Service Provider has an ATCID, but it does not include one or two of the information items described in R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>**OR**<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include three or more of the information items described in R3. |
| R4. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, but not more than 30 calendar days after, its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 90 calendar days after its implementation.<br>**OR**<br>The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation. |
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in R4. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R6. | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |
| R7 | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10%, of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |
| R8. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | ▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. | ▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days. |
| R9 | N/A | The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available more than 30 calendar days but less than 45 calendar days after receiving a request. | The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available 45 calendar days or more but less than 60 calendar days after receiving a request. | The Transmission Service Provider did not make the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available for 60 calendar days or more after receiving a request. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC Authorized posting TTC/ATC/AFC SAR Development June 20 2005.
2. SAC Authorized the SAR to be developed as a standard on February 14 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from February 15–March 16, 2007.
5. SDT posted second draft for comment from May 25–June 25, 2007.
6. SDT posted third draft for comment from October 31–December 15, 2007.
7. SC conducted an Initial Ballot of the standard from March 3–12, 2008.
8. SDT posted fourth draft for comment form April 16–May 15, 2008.

**Description of Current Draft:**

This is the fifth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Respond to Comments. | June 20, 2008 |
| 2. Posting for 30-day Pre-Ballot Review. | June 20, 2008 |
| 3. Initial Ballot. | July 21, 2008 |
| 4. Respond to comments. | August 20, 2008 |
| 5. Recirculation ballot. | August 21, 2008 |
| 6. 30-day posting before board adoption. | June 21, 2008 |
| 7. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**ATC Path:** ~~Any Posted Path or~~ Aany ~~other~~ combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[1].

**Available Transfer Capability (ATC):** A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Eexisting Ttransmission Ccommitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.

**Available Transfer Capability Implementation Document (ATCID):** A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.

**Transmission Operator Area:** The collection of Transmission assets over which the Transmission Operator is responsible for operating.

**Existing Transmission Commitments (ETC):** Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

**Planning Coordinator:** See Planning Authority.

**Postback:** Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

**Business Practices:** Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices**.**

**Block Dispatch:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

**Dispatch Order:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

**Participation Factors:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

[1] See 18 CFR 37.6(b)(1)

## A. Introduction

1. **Title:** **Available Transmission System Capability**

2. **Number:** **MOD-001-1**

3. **Purpose:** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors

4. **Applicability:**

   **4.1.** Transmission Service Provider.

   **4.2.** Transmission Operator.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** Each Transmission Operator shall select one of the ~~ATC~~ methodolog~~y~~ies[2] listed below for calculating Available Transfer Capability (ATC) ~~ATC (Area Interchange methodology, Rated System Path methodology)~~ or -Available Flowgate Capability (AFC) ~~AFC (Flowgate methodology)~~ for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area~~.~~: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- The Area Interchange Methodology, as described in MOD-028
- The Rated System Path Methodology, as described in MOD-029
- The Flowgate Methodology, as described in MOD-030

**R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Lower* [*Time Horizon: Operations Planning*]

**R2.1.** Hourly values for at least the next 48 hours.

**R2.2.** Daily values for at least the next 31 calendar days.

**R2.3.** Monthly values for at least the next 12 months (months 2-13).

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows including:

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[2] All ATC Paths do not have to use the same methodology and no particular ATC Path must use the same methodology for all time periods.

**R3.2.1.** How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

**R3.2.2.** A rationale for th~~e defined~~ at accounting specified in R3.2. ~~.~~

**R3.3.** The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC ~~transfer of Flowgate capability~~or AFC.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.

**R3.5.** A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

**R3.6.** A description of how generation and transmission outages are considered in ~~ATC~~ transfer or Flowgate capability calculations, including:

**R3.6.1.** The criteria used to determine when an outage that is in effect part of a day impacts a daily ~~ATC or AFC~~ calculation.

**R3.6.2.** The criteria used to determine when an outage that is in effect part of a month impacts a monthly ~~ATC or AFC~~ calculation.

**R3.6.3.** How outages from other Transmission Service Providers ~~(including those outages from other Transmission Service Providers that are unrecognized)~~that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are ~~processed~~addressed~~,~~.

**R4.** The Transmission Service Provider shall notify the following entities ~~(via electronic mail)~~ before implementing a new or revised ATCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

**R4.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

**R4.3.** Each Transmission Operator associated with the Transmission Service Provider's area.

**R4.4.** Each Planning Coordinator adjacent to the Transmission Service Provider's area.

**R4.5.** Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

**R4.6.** Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

**R5.** The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.** When calculating Total ~~t~~Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.** When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to ~~80~~ 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.

**R8.2.** Daily values, once per day.

**R8.3.** Monthly values, once per week.

**R9.** Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor's ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations

Note that the North American Energy Standards Board (NAESB) is developing the companion standards that address the posting of ATC information, including supporting information such as that described in R9.

- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM)~~, and TTC~~ for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

**R9.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

**R9.1.1.** If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available

**R9.1.2.** If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available

**R9.1.3.** If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available

**R9.2.** This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one of the specified methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator's operating area. (R1).

**M2.** The Transmission Service Provider shall provide ATC or AFC values and identification of the selected methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 48 hours of hourly values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly values calculated at all times (Months 2-13). (R2.3)

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** The Transmission Service Provider shall provide evidence (such as dated electronic mail messages, mail receipts, or voice recordings) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

**M5.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

**M6.** The Transmission Operator shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides~~, load shedding~~ or data sources for load forecast and facility outages) used to calculate TTC or TFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC or TFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC ~~-~~and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

**M7.** The Transmission Service Provider shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides~~, load shedding~~ or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

**M8.** The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly values on at least the minimum frequencies specified in R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R8)

**M9.** The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R9. (R9)

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Data Retention**

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

-The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Operator did not select one of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. |
| R2. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours.<br>~~OR~~<br>▪ Has calculated daily ATC or AFC values for more than the next 21 calendar days but less than the next 31 calendar days.<br>~~OR~~<br>▪ Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours.<br>~~OR~~<br>▪ Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days.<br>~~OR~~<br>▪ Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 21 hours.<br>~~OR~~<br>▪ Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days.<br>~~OR~~<br>▪ Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated ~~less than 11~~ hourly ATC or AFC values for less than the next 11 hours.<br>~~OR~~<br>▪ Has c~~C~~alculated ~~less than 8~~ daily ATC or AFC values for less than the next 8 calendar days.<br>~~OR~~<br>▪ Has c~~C~~alculated ~~less than4~~ monthly ATC or AFC values for less than the next 4 months.<br>~~OR~~<br>▪ Did not use the selected methodology(ies) to calculate ATC. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>**OR**<br>The Transmission Service Provider has an ATCID, but it does not include one or two ~~or more~~ of the information items described in R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>**OR**<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include ~~any~~ three or more of the information items described in R3. |
| R4. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, but not more than 30 calendar days after, its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation. | The Transmission Service Provider ~~did not notify~~notified one or more of the parties specified in R4 of a new or modified ATCID ~~for~~ more than 90 calendar days after its implementation.<br>**OR**<br>The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation. |
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in R4. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R6. | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |
| R7 | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10%, of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |
| R8. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the ~~80~~175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the ~~80~~175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the ~~80~~175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the ~~80~~175-hour per year requirement. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | ~~OR~~<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>~~OR~~<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. | ~~OR~~<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>~~OR~~<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | ~~OR~~<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>~~OR~~<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | ~~OR~~<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>~~OR~~<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days. |
| R9 | N/A | The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available more than 30 calendar days but less than 45 calendar days after receiving a request. | The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available 45 calendar days or more but less than 60 calendar days after receiving a request. | The Transmission Service Provider did not make the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available for 60 calendar days or more after receiving a request. |

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## Implementation Plan for Standard MOD-001-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-001-1 – Available Transfer Capability which requires the selection of an ATC methodology and describes the parts of the ATC process that apply to all entities, regardless of methodology chosen.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### Retired Standards

This standard supersedes the current MOD-001-0.

FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-001-1 incorporates the requirements from FAC-012-1 as follows:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

FAC-013-1 – Establish and Communicate Transfer Capabilities, includes two requirements. MOD-001-1 incorporates the two requirements from FAC-013-1 as follows:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-001-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Implementation Plan for Standard MOD-001-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-001-1 – Available Transfer Capability which requires the selection of an ATC methodology and describes the parts of the ATC process that apply to all entities, regardless of methodology chosen.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Retired Standards

This standard supersedes the current MOD-001-0.

FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-001-1 incorporates the requirements from FAC-012-1 as follows:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

FAC-013-1 – Establish and Communicate Transfer Capabilities, includes two requirements. MOD-001-1 incorporates the two requirements from FAC-013-1 as follows:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-001-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Summary of Process Steps Taken Following Posting of the Standards for 30-day Comment

The ATC Standard Drafting Team is developing the ATC-related standards, in part, as a response to FERC Order 890. Order 890 provided specific guidance on the timeliness of this standards development effort. The drafting team has been working to a strict time line to ensure it can file these standards in compliance with the Commission's directives, while also adhering to the NERC Reliability Standards Development Procedure.

As described in Step 8 of NERC's Reliability Standards Development Procedure,

> "Based on the comments received and field testing, the standard drafting team may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the effect or use of the standard."

When reviewing the comments received and considering changes to the standards, the drafting team also considered that any substantive changes to the requirements would require an additional 30-day comment and response period, which would eliminate the possibility of meeting the FERC's submission deadlines. The drafting team carefully weighed the reliability benefit of any changes to the standard, and attempted to limit its modifications to those that clarify or explain, rather than create new requirements or change intent. The changes to the standards made by the drafting team fall into one or more of the following categories:

- Corrections
- Redrafting of language that does not change intent
- Clarifications that better explain intent
- Modifications that change minor details, but not intent
- Modifications to ensure consistency and reduce ambiguity

The drafting team does not believe that any of the changes made to the requirements following the last comment period directly or materially affect the effect or use of the standards, but instead make the standards more clear.

The NERC Standards Committee is a stakeholder group responsible for the oversight of standards development, including evaluation of the responses to comments and any changes to the standards. As described in Step 8 of NERC's Reliability Standards Development Procedure:

> "When the Standards Committee receives a draft standard that is recommended for ballot, the Standards Committee will review the standard and recommendations of the standards process manager to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives and requirements cited in Steps 1 to 8, as applicable; has an implementation plan; and is compatible with other existing standards. If the proposed standard does not pass this review, the Standards Committee shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the Standards

> Committee shall set the proposed standard for ballot as soon as the work flow will accommodate."

NERC's Standards Process Manager presented the changes described above to the Executive Committee of the NERC Standards Committee on June 19, 2008. Following review of the revisions made to the standards, comment responses, and implementation plans, the Standards Committee's Executive Committee determined that the standards had passed the review, and the changes made do not directly or materially affect the effect or use of the standards. The Standards Committee's Executive Committee directed NERC's Standards Process Manager to post the standards for 30-day pre-ballot review and to begin assembling the ballot pools necessary for balloting.

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**Reliability Standards**



| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC et al Standard - MOD-001_in |
| **Ballot Period:** | 7/21/2008 - 7/30/2008 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 220 |
| **Total Ballot Pool:** | 234 |
| **Quorum:** | **94.02 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 75.97 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

**Summary of Ballot Results**

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 65 | 1 | 44 | 0.772 | 13 | 0.228 | 3 | 5 |
| 2 - Segment 2. | 9 | 0.6 | 6 | 0.6 | 0 | 0 | 2 | 1 |
| 3 - Segment 3. | 63 | 1 | 46 | 0.836 | 9 | 0.164 | 6 | 2 |
| 4 - Segment 4. | 13 | 1 | 5 | 0.455 | 6 | 0.545 | 2 | 0 |
| 5 - Segment 5. | 39 | 1 | 25 | 0.735 | 9 | 0.265 | 3 | 2 |
| 6 - Segment 6. | 28 | 1 | 18 | 0.72 | 7 | 0.28 | 0 | 3 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 3 | 0.2 | 2 | 0.2 | 0 | 0 | 1 | 0 |
| 9 - Segment 9. | 6 | 0.5 | 5 | 0.5 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.7 | 5 | 0.5 | 2 | 0.2 | 0 | 0 |
| **Totals** | **234** | **7** | **156** | **5.318** | **46** | **1.682** | **18** | **14** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Ameren Services Company | Kirit S. Shah | Negative | View |
| 1 | American Electric Power | Paul B. Johnson | Negative | View |
| 1 | American Transmission Company, LLC | Jason Shaver | Affirmative | |
| 1 | Arizona Public Service Co. | Cary B. Deise | Affirmative | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Basin Electric Power Cooperative | David Rudolph | Negative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | |
| 1 | Brazos Electric Power Cooperative, Inc. | Tony Kroskey | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | Central Lincoln PUD | Ronald Beck | Affirmative | |
| 1 | Central Maine Power Company | Brian Conroy | | |
| | City of Tacoma, Department of Public | | | |

| | | | | |
|---|---|---|---|---|
| 1 | Utilities, Light Division, dba Tacoma Power | Alan L Cooke | Affirmative | |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | E.ON U.S. LLC | Larry Monday | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Affirmative | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Affirmative | |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | |
| 1 | Lincoln Electric System | Doug Bantam | Affirmative | |
| 1 | Manitoba Hydro | Michelle Rheault | Affirmative | |
| 1 | Minnesota Power, Inc. | Carol Gerou | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Negative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Abstain | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Negative | View |
| 1 | Orlando Utilities Commission | Brad Chase | Affirmative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Affirmative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Progress Energy Carolinas | Sammy Roberts | Affirmative | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Abstain | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Affirmative | View |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Western Farmers Electric Coop. | Alan Derichsweiler | | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | | |
| | British Columbia Transmission | | | |

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|---|---|---|---|---|
| 2 | Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | View |
| 2 | New Brunswick System Operator | Alden Briggs | Affirmative | |
| 2 | New York Independent System Operator | Gregory Campoli | Abstain | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Ameren Services Company | Mark Peters | Negative | View |
| 3 | American Electric Power | Raj Rana | Negative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Affirmative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Blachly-Lane Electric Co-op | Bud Tracy | Affirmative | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | |
| 3 | City of McMinnville | Rick Rozanski | Affirmative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Negative | View |
| 3 | Clatskanie People's Utility District | Joseph Taffe | Affirmative | |
| 3 | Clearwater Power Co. | Dave Hagen | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Constellation Energy | Carolyn Ingersoll | Affirmative | View |
| 3 | Consumers Energy | David A. Lapinski | Abstain | |
| 3 | Coos-Curry Electric Cooperative, Inc | Roger Meader | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Grays Harbor PUD | Wesley W Gray | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Affirmative | |
| 3 | Lincoln Electric System | Bruce Merrill | Affirmative | |
| 3 | Lost River Electric Cooperative | Richard Reynolds | Affirmative | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Affirmative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | Nevada Power Co. | Sheryl Torrey | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Northern Indiana Public Service Co. | William SeDoris | Negative | |
| 3 | Northern Lights Inc. | Jon Shelby | Affirmative | |
| 3 | Northern Wasco County People's Utility District (PUD) | Paul Titus | Affirmative | |
| 3 | Okanogan County Electric Cooperative, Inc. | Ray Ellis | Affirmative | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Affirmative | |
| 3 | Progress Energy Carolinas | Sam Waters | Affirmative | |

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|---|---|---|---|---|
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Abstain | |
| 3 | Public Utility District No. 1 of Benton County | Gloria Bender | Affirmative | |
| 3 | Public Utility District No. 1 of Franklin County | Linda Boomer | Abstain | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Affirmative | |
| 3 | Raft River Rural Electric Cooperative | Heber Carpenter | Affirmative | |
| 3 | Salmon River Electric Cooperative | Ken Dizes | Affirmative | |
| 3 | Salt River Project | John T. Underhill | Affirmative | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | | |
| 3 | Umatilla Electric Cooperative | Steve Eldrige | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | Alliant Energy Corp. Services, Inc. | Kenneth Goldsmith | Negative | View |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Affirmative | |
| 4 | Northern California Power Agency | Fred E. Young | Affirmative | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Negative | |
| 4 | Pacific Northwest Generating Cooperative | Aleka K Scott | Affirmative | |
| 4 | Public Power Council | Nancy Baker | Negative | |
| 4 | Public Utility District No. 1 of Douglas County | Henry E. LuBean | Negative | View |
| 4 | Public Utility District No. 1 of Snohomish County | John D. Martinsen | Abstain | |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 4 | WPS Resources Corp. | Christopher Plante | Negative | View |
| 5 | AEP Service Corp. | Brock Ondayko | Negative | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | |
| 5 | City of Farmington | Clinton J Jacobs | Affirmative | |
| 5 | City of Tallahassee | Alan Gale | Abstain | |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Negative | View |
| 5 | Deseret Power | Philip B Tice Jr | Affirmative | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Negative | View |
| 5 | Entergy Corporation | Stanley M Jaskot | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | IBERDROLA RENEWABLES | Laura Beane | Affirmative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Affirmative | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Affirmative | |
| 5 | New York Power Authority | Gerald Mannarino | Affirmative | |
| 5 | Orlando Utilities Commission | Richard Kinas | Abstain | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Affirmative | |
| 5 | Reliant Energy Services | Thomas J. Bradish | Negative | View |

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|---|---|---|---|---|
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seattle City Light | Michael J. Haynes | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | | |
| 5 | Southeastern Power Administration | Douglas Spencer | Affirmative | |
| 5 | Southern California Edison Co. | David Schiada | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | U.S. Bureau of Reclamation | Martin Bauer | | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Affirmative | |
| 6 | AEP Marketing | Edward P. Cox | Negative | |
| 6 | Barry Green Consulting Inc. | Barry Green | Negative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Negative | View |
| 6 | Dominion Resources, Inc. | Louis S Slade | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | IBERDROLA RENEWABLES | Kellie J Schreiner | Affirmative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Affirmative | |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Luminant Energy | Thomas Burke | | |
| 6 | Manitoba Hydro | Daniel Prowse | Affirmative | |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Affirmative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Affirmative | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Affirmative | |
| 6 | Reliant Energy Services | Trent Carlson | Negative | View |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | Southern California Edison Co. | Marcus V Lotto | Affirmative | |
| 6 | Tampa Electric Co. | Jose Benjamin Quintas | | |
| 6 | Tenaska Power Services Co. | Cliff T Richardson | Negative | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Affirmative | |
| 7 | Eastman Chemical Company | Lloyd Webb | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Abstain | |
| 8 | Other | Michehl R. Gent | Affirmative | |
| 8 | Volkmann Consulting | Terry Volkmann | Affirmative | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | | |
| 9 | Oregon Public Utility Commission | Jerome Murray | Affirmative | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Negative | View |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |

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| 10 | SERC Reliability Corporation | Carter B Edge | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

609.452.8060 (Voice) - 609.452.9550 (Fax)
116-390 Village Boulevard, Princeton, New Jersey 08540-5721

| Entity | Segment | Vote | Comment |
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| Ameren Services Company | 1 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-001-1. Under R1, the Transmission Service Provider not the Transmission Operator should be responsible for selection of the ATC/AFC methodology. This is especially true when the Transmission Service Provider determines ATC for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO. R5 suggests that the Transmission Operator is responsible to calculate TTC or TFC. This is not supported by the current version of the Functional Model. Determining TTC (TFC) is a planning function supported by the Transmission Planner. The majority of requirements are limited to the Operations Planning Time Horizon. TTC (TFC) and ATC (TFC) are also parameters which are relevant in the plus one year. |
| American Electric Power | 1 | Negative | AEP would have voted affirmatively for this standard had seemingly minor clarifications been included. This negative vote is for the following reasons: This standard, as written, has largely divorced itself from the previous references of ATC and its connection to 'selling' unused transmission 'capacity'. And, as such, the Purpose section in this proposed standard presupposes that these calculations are to be (or is being) done and are necessary for reliability. The purpose clearly states "To ensure calculations are performed ..... to maintain awareness of available transmission capability and future flows...." This is simply not the case for a large portion of the bulk electric system. As an example, ERCOT does not have any "ATC paths" internal to ERCOT and therefore does not calculate ATC for the transmission system internal to ERCOT. However, the proposed revision to MOD 001 does not clearly state where (which paths) ATC must be calculated or where it should not (or need not) be calculated. Although one could assume that ATC is not intended to require ATC calculations for "internal Paths" -- the standard is less than clear in this regard. However this proposed Standard requires that each Transmission Operator (per R1) select a method a method of calculation "for each ATC path ...... for those Facilities within its Transmission operating area" , strongly implies or at least allows a far more reaching, unnecessary and burdensome interpretation. In addition, the definition of ATC Path states ..."any combination of POR and POD for which ATC is calculated and any Posted Path." And the definition of ATC states — measure of transfer capability remaining in the physical transmission network for further commercial activity..." It is unclear how to interpret "further commercial activity" in a market such as ERCOT's. (ERCOT does not 'sell' transmission service). This alone could cause unwarranted concern, or needless ambiguity during implementation of this standard or some future audit -- and/or necessitates creation of a regional standard. The standard is also internally inconsistent. The Purpose presupposes that the calculation is being (or needs to be) performed. R1 requires that "Each Transmission Provider" must select a methodology. The standard does not define for which PRO/POD pairings (ATC Paths) ATC must be calculated. However, for existing tariff and other reasons, ATC is not currently be calculated for a large portion of the bulk electric system. It is unclear if this standard will now require ATC to be calculated where it is currently not being and not needed to be calculated. Much of the dismay of this proposed standard could have been mitigated by adding the clarification — that this standard (or the calculation of ATC) does NOT pertain to any POR/POD pairings internal to a particular Transmission Service Provider (or Balancing Authority) but rather between two or more synchronously |

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| | | | connected 'neighbors'. Without this clarification, we believe that there is a high risk of unintended consequences, and therefore, must vote against |
| Brazos Electric Power Cooperative, Inc. | 1 | Negative | Brazos votes NEGATIVE for this standard as written as it imposes obligations on entities in the ERCOT region that do not utilize ATC paths and calculation methodologies to manage congestion or for reliability operations. Our previous submitted comments suggested that applicability language be included in requirement R1 to recognize that such market difference exists. |
| CenterPoint Energy | 1 | Negative | CenterPoint Energy has previously commented to the ballot pool that we do not support this standard until the standard is clarified. In the interest of brevity, CenterPoint Energy will not repeat its earlier comments. |
| Exelon Energy | 1 | Affirmative | General comment These standards bring the industry closer to a unified ATC calculation methodology by requiring that one of three calculation methodologies be utilized and documented. This is an improvement from where the industry is today but falls short of FERC Order No. 890. The standards still lack a requirement for ATC or AFC calculations to be consistent with criteria used in operating and planning studies for corresponding time periods. Exelon's comments reflect these deficiencies and Exelon will be making these same points to FERC if these standards are approved, requesting that the FERC direct NERC to approve the standards but modify the standards to be consistent with Order No. 890. Suggested modifications to the standards to achieve this consistency are included in our comments. MOD-001-1 Available Transmission System Capability The purpose of the standard does align with the requirements specified. There are no requirements that would “ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors”. The following wording is suggested for the purpose: To ensure that Available Transmission System Capability calculations performed by Transmission Service Providers are documented and performed using one of the three methodologies specified in this standard. R6 and R7 need to be revised to reflect consistency with both planning and operating studies for corresponding time periods studied. The term “planning of operations” is not a defined term and one that is not commonly used by all electric utility entities. The following wording is suggested for R6 and R7: R6. When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in operating studies and planning studies for the corresponding time period studied. R7. When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in operating studies and planning studies for the corresponding time period studied. In R3 add requirements to specify the following: PTDF and OTDF cutoff values used Source and sink point determination and use |
| FirstEnergy Energy Delivery | 1 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-001 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require |

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| | | | delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-001 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-001 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R1: Selection the ATC or AFC methodology - R6: Calculation of TTC or TFC. Additional Comments: R1 â€" Selection of ATC or AFC Methodology(ies): We appreciate the effort taken by the SDT during the last comment period in seeking industry feedback regarding which responsible entity, the Transmission Service Provider (TSP) or Transmission Operator (TOP), should be responsible for selecting the ATC or AFC methodology used to calculate ATC or AFC. In the SDT team's response to industry comments it was indicated that 13 out of 35 responders felt the TSP is the appropriate responsible entity and it was the SDT's opinion that this did not show consensus from the industry to change the SDT's proposed assignment of the requirement to the TOP. However, the SDT failed to recognize that only 7 favored the TOP and that 15 respondents were indifferent to the TSP or TOP being assigned. The SDT's action to keep the TOP as the responsible entity assumes the team was correct in its initial assignment. In reality, the review of data from industry should have been 7 for TOP and 13 for TSP. This is nearly a 2 to 1 response in favor of the TSP selecting the methodology. Therefore, FE believes the SDT failed to make the appropriate adjustment and that the TSP is the appropriate responsible entity for this requirement. |
| Great River Energy | 1 | Negative | Great River Energy (GRE) thanks the NERC ATC/CBM/TRM standard drafting team for all of their efforts in the creation of this standard. However, GRE is concerned with the Transmission Operator being assigned as the responsible entity for R1 and R6 in MOD-001. It is GRE's opinion that the responsible entity for R1 and R6 should be the Transmission Service Provider. |
| Oncor Electric Delivery | 1 | Negative | Oncor votes NO on this standard due to continuing objection to applicability. This standard imposes obligations on Transmission Operators and Transmission Service Providers to take actions involving ATC paths and calculation methodologies in physical markets where those methodologies are not used to reliably manage congestion nor are they needed to maintain reliability. For example R1 requires Transmission Operators to select one of three methodologies to calculate something that has no need to be calculated in the ERCOT market and perhaps in other areas as well. This concern has been expressed to the drafting team and they continue to say that the variance process is the way to deal with this concern. |

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| | | | In our opinion that is inappropriate behavior for a drafting team. If they know that there is not a reliability need to impose an obligation on certain market participants then the drafting team should do the work to correct that within the standard itself rather than passing the buck to the market participant to do variance work. The drafting team is knowingly imposing a construct that is used in the Eastern Interconnection as the only way to do something when they full well know that there are other methodologies used in other interconnections that are effective at meeting the underlying reliability needs. |
| Sierra Pacific Power Co. | 1 | Affirmative | Affirmative vote; however, I would like to point out a disagreement with R9 of the Standard MOD-001-1. It doesn't appear to me that a Planning Coordinator or Reliability Coordinator would have a plausible need for the data requested in the sub-items of R9, as they are to be used "solely for the requestor's ATC calculations". In R7, I believe that the Requirement should be revised to allow for differences between operational planning and the calculation of ATC values, as this is necessary in a dynamic environment. |
| Tucson Electric Power Co. | 1 | Affirmative | TEP supports WECC Team remedial language clarifying VSL severity level. |
| Independent Electricity System Operator | 2 | Affirmative | The revised R3.6.3 may lead to confusion. The term “outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability” is subject to interpretation, which needs clarifying. Specific to R6 and R7 - The wording “no more limiting than” as opposed to using something like “consistent with” may give rise to the use of less limiting assumptions. The qualifying phrase appended to these requirements “providing such planning of operations has been performed for that time period” does not provide any value, nor does it address the issue brought up above. |
| Midwest ISO, Inc. | 2 | Abstain | R3.5: Various Joint Operating Agreements (JOA) and other stand alone documents that describe the flowgate allocation processes for Midwest ISO and its neighboring entities are already posted on public websites. Midwest ISO does not believe it is reasonable to include the identical content in the ATCID that is in another stand alone document, whose contents could contain considerable length. Instead, Midwest ISO believes referencing appropriate documents via links included in the ATCID is an acceptable alternative that will prevent updating multiple documents due to a revision in a JOA. Thus, Midwest ISO submits the following revision to R3: R3: Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information or links to posted documents that contain the following information: R6: Midwest ISO continues to believe that the phrase “no more limiting” is not clear for all specific assumptions used when calculating TTC or TFC. This seems to leave it up to the individual auditor to make a decision to decide which assumption is more limiting. We believe that the essence of a standard is to remove subjectivity from the determination of compliance. R7: Midwest ISO continues to believe that the phrase “no more limiting” is not clear for all specific assumptions used when calculating TTC or TFC. This seems to leave it up to the individual auditor to make a decision to decide which assumption is more limiting. We believe that the essence of a standard is to remove subjectivity from the determination of compliance. |
| New York Independent | 2 | Abstain | The NYISO abstains from voting on this proposed standard. The NYISO appreciates recent feedback from the Standards Drafting Team on several rounds of comments requesting that revisions be made to the |

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| System Operator | | | language of this proposed standard in order to: (i) expressly accommodate the NYISO's FERC-approved market design and financial reservation based open access transmission system; and (ii) eliminate any possible question as to whether the NYISO's existing approach to calculating ATC satisfies the requirements of the proposed standards. The Standards Drafting Team has indicated that it believes that the NYISO's existing procedures are compliant with the proposed standard. Nevertheless, the NYISO is abstaining in order to preserve its rights to seek a formal confirmation of its compliance from FERC or NERC. |
| Ameren Services Company | 3 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-001-1. Under R1, the Transmission Service Provider not the Transmission Operator should be responsible for selection of the ATC/AFC methodology. This is especially true when the Transmission Service Provider determines ATC for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO. R5 suggests that the Transmission Operator is responsible to calculate TTC or TFC. This is not supported by the current version of the Functional Model. Determining TTC (TFC) is a planning function supported by the Transmission Planner. The majority of requirements are limited to the Operations Planning Time Horizon. TTC (TFC) and ATC (TFC) are also parameters which are relevant in the plus one year. |
| City Public Service of San Antonio | 3 | Negative | I cannot vote for this standard as written. It needs to acknowledge definitive alternatives to ATC for regions or markets such as ERCOT where transmission service markets are not used. |
| Constellation Energy | 3 | Affirmative | Greater standardization in the use of counterflows is required. |
| FirstEnergy Solutions | 3 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-001 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-001 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with |

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| | | | the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-001 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R1: Selection the ATC or AFC methodology - R6: Calculation of TTC or TFC. Additional Comments: R1 â€“ Selection of ATC or AFC Methodology(ies): We appreciate the effort taken by the SDT during the last comment period in seeking industry feedback regarding which responsible entity, the Transmission Service Provider (TSP) or Transmission Operator (TOP), should be responsible for selecting the ATC or AFC methodology used to calculate ATC or AFC. In the SDT team's response to industry comments it was indicated that 13 out of 35 responders felt the TSP is the appropriate responsible entity and it was the SDT's opinion that this did not show consensus from the industry to change the SDT's proposed assignment of the requirement to the TOP. However, the SDT failed to recognize that only 7 favored the TOP and that 15 respondents were indifferent to the TSP or TOP being assigned. The SDT's action to keep the TOP as the responsible entity assumes the team was correct in its initial assignment. In reality, the review of data from industry should have been 7 for TOP and 13 for TSP. This is nearly a 2 to 1 response in favor of the TSP selecting the methodology. Therefore, FE believes the SDT failed to make the appropriate adjustment and that the TSP is the appropriate responsible entity for this requirement. |
| MidAmerican Energy Co. | 3 | Negative | I am concerned with R7 and M7. I do not see how technically models can be created day to day to use in operational planning that incorporate transmission service requests that change instantaneously each and every day. Also, I believe TRM should not be used in operational planning. I recommend that R7 and M7 be revised to specifically allow differences between operational planning and ATC and AFC for transmission service requests and TRM. |
| Wisconsin Public Service Corp. | 3 | Negative | R7 and M7 of MOD-001-1 should be revised to specifically allow differences between operational planning and calculating ATC and AFC for transmission service requests and for TRM. Incorporating transmission service requests, which change frequently, into operational planning models is problematic. Also, TRM can be used to calculate ATC and AFC and that TRM should not be used in operational planning. The Transmission Operator should not be the responsible entity for R1 and R6 in MOD-001, it should be the Transmission Service Provider. |
| Alliant Energy Corp. Services, Inc. | 4 | Negative | We are concerned with R7 and M7. We do not see how it is feasible technically to create models day to day for use in operational planning that incorporate transmission service requests that change instantaneously day to day. We also believe TRM can be used to calculate ATC and AFC and that TRM should not be used in operational planning. We beleve the responsible entity in R1 and R6 should be the Transmission Service Provider. |
| Public Utility District No. 1 of Douglas County | 4 | Negative | We have not had sufficient time to review the effects of this change and coordinate it with others in our region. |
| WPS Resources | 4 | Negative | Requirement R5. The ATCID should be made available to all users, owners, and operators. That is, the document should be publicly available. R1 and R6 should be the responsibility of the Transmission Service |

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| Corp. | | | Provider. |
| Constellation Generation Group | 5 | Negative | Greater standardization in the use of counterflows is required then provided in this standard. |
| Electric Power Supply Association | 5 | Negative | There should be greater standardization regarding the use of counterflows. |
| Entegra Power Group, LLC | 5 | Negative | Gentlemen, we should be pursuing a transmission service model which would grant or deny ATC that is "AS ACCURATE AS POSSIBLE". Therefore, the following should be implemented: Daily, weekly, and monthly ATC models should contain the "actual generation that is expected to run for that period" included in the model. Discrete elements, up to 3 buses, for neighboring regions. Interregional Coordination. The model should not be allowed to contain 1st contingency Base Case Overloads. LARRY RODRIGUEZ Manager - Regulatory & Transmission Entegra Power Services 100 S. Ashley St, Suite 1400 Tampa, FL 33602 Business (813) 301-4952 Fax (813) 301-4990 Cell (813) 293-8447 lrodriguez@entegrapower.com |
| FirstEnergy Solutions | 5 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-001 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-001 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-001 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R1: Selection the ATC or AFC methodology - R6: Calculation of TTC or TFC. Additional Comments: R1 â€" Selection of ATC or AFC Methodology(ies): We appreciate the effort taken by the SDT during the last comment period in seeking industry feedback regarding which responsible entity, |

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| | | | the Transmission Service Provider (TSP) or Transmission Operator (TOP), should be responsible for selecting the ATC or AFC methodology used to calculate ATC or AFC. In the SDT team's response to industry comments it was indicated that 13 out of 35 responders felt the TSP is the appropriate responsible entity and it was the SDT's opinion that this did not show consensus from the industry to change the SDT's proposed assignment of the requirement to the TOP. However, the SDT failed to recognize that only 7 favored the TOP and that 15 respondents were indifferent to the TSP or TOP being assigned. The SDT's action to keep the TOP as the responsible entity assumes the team was correct in its initial assignment. In reality, the review of data from industry should have been 7 for TOP and 13 for TSP. This is nearly a 2 to 1 response in favor of the TSP selecting the methodology. Therefore, FE believes the SDT failed to make the appropriate adjustment and that the TSP is the appropriate responsible entity for this requirement. |
| Reliant Energy Services | 5 | Negative | Reliant Energy, Inc. is concerned the proposed MOD-001-1 would include the ERCOT Region (TOP, TSP) in the NERC requirements to calculate ATC. ERCOT uses the CSC methodology that differs from the ATC methodology used in the eastern interconnection. This change would serve no reliability purpose in ERCOT, which operates as a single control area. As such, the standard should contain exclusionary language added for ERCOT so as not to apply to the ERCOT Region. |
| Barry Green Consulting Inc. | 6 | Negative | Greater standardization in the use of counterflows is required |
| Constellation Energy Commodities Group | 6 | Negative | Greater standardization in the use of counterflows is required. |
| FirstEnergy Solutions | 6 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-001 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-001 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered |

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| | | | when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-001 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - R1: Selection the ATC or AFC methodology - R6: Calculation of TTC or TFC. Additional Comments: R1 â€" Selection of ATC or AFC Methodology(ies): We appreciate the effort taken by the SDT during the last comment period in seeking industry feedback regarding which responsible entity, the Transmission Service Provider (TSP) or Transmission Operator (TOP), should be responsible for selecting the ATC or AFC methodology used to calculate ATC or AFC. In the SDT team's response to industry comments it was indicated that 13 out of 35 responders felt the TSP is the appropriate responsible entity and it was the SDT's opinion that this did not show consensus from the industry to change the SDT's proposed assignment of the requirement to the TOP. However, the SDT failed to recognize that only 7 favored the TOP and that 15 respondents were indifferent to the TSP or TOP being assigned. The SDT's action to keep the TOP as the responsible entity assumes the team was correct in its initial assignment. In reality, the review of data from industry should have been 7 for TOP and 13 for TSP. This is nearly a 2 to 1 response in favor of the TSP selecting the methodology. Therefore, FE believes the SDT failed to make the appropriate adjustment and that the TSP is the appropriate responsible entity for this requirement. |
| Reliant Energy Services | 6 | Negative | Reliant Energy, Inc. is concerned the proposed MOD-001-1 would include the ERCOT Region (TOP, TSP) in the NERC requirements to calculate ATC. ERCOT uses the CSC methodology that differs from the ATC methodology used in the eastern interconnection. This change would serve no reliability purpose in ERCOT, which operates as a single control area. As such, the standard should contain exclusionary language added for ERCOT so as not to apply to the ERCOT Region. |
| Electric Reliability Council of Texas, Inc. | 10 | Negative | The standard as proposed contains no clear applicability only to those Transmission Operators or Transmission Service providers who utilize ATC in their transmission system and market operations. |
| Midwest Reliability Organization | 10 | Negative | The MRO is concerned with R7 and M7. We do not see how technically models can be created day to day for use in operational planning that incorporate transmission service requests that change instantaneously each and every day. Also, we believe TRM can be used to calculate ATC and AFC and that TRM should not be used in operational planning. We believe that R7 and M7 of MOD-001-1 should be revised to specifically allow differences between operational planning and ATC and AFC for transmission service requests and for TRM. |

# Consideration of Comments on Initial Ballot — MOD-008-1 — Transmission Reliability Margin Calculation Methodology

**Summary Consideration:** While some stakeholders suggested modifications to the standard, most stakeholders agreed with the standard as proposed and the drafting team did not make any changes to the standard.

| Entity | Segment | Vote | Comment |
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| Ameren Services Company | 1 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-008-1.<br><br>(1) Applicability: The Transmission Service Provider not the Transmission Operator should be responsible for TRM methodology. This is especially true when the Transmission Service Provider determines TRM for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO.<br><br>(2) Is TRM a reliability parameter or a market parameter? While the concepts of uncertainty and sensitivity analysis are inherent in reliability planning TRM as a metric has not been previously defined in the planning process. TRM has been applied in sale of open access transmission system to limit exposure to oversubscription of transmission service. As such TRM should be the responsibility of the Transmission Service Provider.<br><br>(3) That said we are aware that the oversubscription of transmission service can lead to reliability problems.<br><br>(4) The Transmission Service Provider, Transmission Operator, Planning Coordinator, and Transmission Planner should coordinate and cooperate in developing the TRM methodology.<br>(5)TRM is applicable in the Operating Time Horizon and the one-year and beyond horizon. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structure; however, we are required to pick a single entity as responsible for this task.<br><br>The SDT believes TRM is a reliability parameter, as the Transmission Operator may expect it to be available as one of its tools to manage the reliability of the system and respond to situations outside expected conditions. | | | |

| Entity | Segment | Vote | Comment |
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| The SDT concurs that oversubscription can lead to reliability problems.<br><br>Developing requirements that require collaboration are difficult, as it can be challenging to discover who is not complying. For example, if MISO and Ameren were unable to come to agreement on development of a TRM methodology, should both entities be sanctioned for not meeting the TRM requirements? NERC has attempted to address this through allowing the use of Joint Registration Organizations, where a MISO/Ameren collaboration would be sanctioned as a single entity, and then the JRO would be responsible for determining how to allocate those sanctions among participants in the JRO.<br><br>With regard to the Time Horizons used in compliance (which are generally used to indicate how much time is available for mitigating a violation to the requirements), the SDT believes the correct horizon is Operations Planning. | | | |
| American Electric Power | 1 | Affirmative | AEP votes affirmative, but we have a concern that the standard appears to have an internal ambiguity. The applicability states “Transmission Operators that maintain TRM" however, R1 requires that “Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) ...." In the context of R1, it unclear what requirements are placed upon Transmission Operators that DOES NOT maintain TRM. In addition, the Purpose statement implies that TRM is used as a real-time operation value. It is not. Despite these reservations, the proposed standard is benign, and AEP does vote affirmative. |
| **Response**: The entire standard only applies to those Transmission Operators that maintain TRM and because this is specified in the applicability, the standard did not reiterate this in the requirements. With regard to the use of TRM as a real-time operation value, the SDT believes that while the TRM may not be explicitly scheduled, the capacity withheld as a margin may be used in real-time (e.g., if load forecast is higher than expected, then some of the margin may be used to support the additional internal generation needed to serve that load). | | | |
| Brazos Electric Power Cooperative, Inc. | 1 | Negative | A NEGATIVE vote is cast for this standard as written as it imposes obligations on entities in the ERCOT region that do not utilize ATC paths and calculation methodologies to manage congestion or for reliability operations. Our previous submitted comments suggested that applicability language be included in the requirements to recognize that such market difference exists. |
| **Response**: If ERCOT does not utilize TRM, then this standard does not apply. | | | |
| Exelon Energy | 1 | Affirmative | General comment These standards bring the industry closer to a unified ATC calculation methodology by requiring that one of three calculation methodologies be utilized and documented. This is an improvement from where the industry is today but falls short of FERC Order No. 890. The standards still lack a requirement for ATC or AFC calculations to be consistent with criteria used in operating and planning studies for corresponding time periods. Exelon's comments reflect these deficiencies and Exelon will be making these same points to FERC if these standards are approved, requesting that the FERC direct NERC to approve the standards but modify the standards to be consistent with Order No. 890. Suggested modifications to the standards to achieve this consistency are included in our comments. MOD-008-1 TRM Calculation Methodology Standard lacks a requirement that |

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| | | | components of TRM be consistent with those used in operating and planning studies for the same time period being studied |
| **Response**: The SDT considered adding the requirement described in previous discussions. However, to do so would negate the value of TRM, as TRM is specifically intended to be based on situations other than those expected. For example, the system might be expected to operate with a load of 10,000 MW. TRM is intended to be used to create a margin such that if load is 11,000 MW, transmission capacity is available to support the serving of that load. In this example, the operations studies performed might include an 11,000 MW case, but would not necessarily include an explicit TRM. The SDT does not believe this to be inconsistent with the intent of Order 890. | | | |
| FirstEnergy Energy Delivery | 1 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-008 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-008 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-008 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - All Requirements (R1 through R5) Additional Comments: Applicability Section - The applicability states "Transmission Operators that maintain TRM" and all requirements of the standard are applicable to the TOP in regards to preparing and maintaining a TRM Implementation Document (TRMID), distributing the TRMID to other interested parties, calculating TRM |

| Entity | Segment | Vote | Comment |
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| | | | consistent with the TRMID, etc. It is unclear to FE what requirements are placed upon a Transmission Operator that DOES NOT maintain TRM. A TOP who does not maintain TRM could be interpreted one of two ways: 1) For a given TOP footprint TRM is not withheld in calculating ATC 2) TRM is withheld for the TOP footprint, but the TOP does not determine or calculate the TRM value withheld. If the appropriate interpretation is as described in item 1) above, it begs the question if this is a needed reliability standard. If TRM is truly a reliability need, it can not be optional for any TOP service area. If the latter, item 2 and FE's understanding, is the correct interpretation, then FE's position on responsibility remains that that the applicability of this standard should rest with the entity performing the calculation of TRM which in many areas of the country is the TSP organization. Since the SDT has elected to not make a change in this regard we are requesting the aforementioned variance for the MISO RTO area. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. The SDT believes the transfer of responsibility described within the MISO Transmission Owners Agreement would be an effective way to delegate this task to a Transmission Service Provider through the registration of a Joint Registration Organization. To the extent an entity variance is desired, First Energy and/or MISO would need to submit a SAR to request the variance. The commenter is correct that ideally a variance would be considered in the SAR process and throughout the standard development process; however, no one has yet requested a variance through a SAR (or incorporated the request into one of the existing SARs during their development), and at this time the drafting team can not add a variance and still meet the deadline established by NERC and FERC for this revision of the standard.<br><br>Regarding the applicability of the standard, the entire standard only applies to those Transmission Operators that operate their system with the assumption that some transmission capacity margin has been withheld from commercial use to address the reliability threats listed in R1. The SDT does not believe that TRM is required for all entities; entities that have reviewed the risks listed in R1 and determined that they can manage those risks through other means (e.g., demand **Response**, operating guides, etc…) are not required to maintain TRM. | | | |
| Great River Energy | 1 | Negative | GRE is concerned with the Transmission Operator being the responsible entity for MOD-008. GRE believes that the responsible entity for these requirements should be the Transmission Service Provider. If the Transmission Operator does not perform this function then a delegation agreement must be created between it and the entity performing the function. It is GRE's opinion that a standard should not knowingly be written in a manner that requires delegation agreements for a large number of responsible entities, doing so is an inefficient use of resources. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; | | | |

| Entity | Segment | Vote | Comment |
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| however, we are required to pick a single entity as responsible for this task. | | | |
| Sierra Pacific Power Co. | 1 | Affirmative | Affirmative vote with comment: The severity levels surrounding R1 still appear to imply that all of the sub-items of R1.1 are expected to be used in the TRMID. It must be clear that it does not constitute a violation if various of these sub-items are not applicable to the TRMID used by the entity. Clarify that this is "as applicable" or "as determined by the entity". |
| **Response**: The VSL indicates that entities must comply with R1.1. R1.1 requires the "Identification of… each of the following components of uncertainty *if used in establishing TRM*" (emphasis added). If the entity does not use a specific element in determining TRM, then its absence would not result in a violation. | | | |
| Southwest Transmission Cooperative, Inc. | 1 | Affirmative | SWTC supports all elements of MOD-08; however, the VSLs as redrafted to accommodate the industry comments have blurred the lines of severity and grant additional discretion to the enforcement entity. Further, the Applicable entity should be clarified throughout the standard to clearly identify whether the standard applies only to TOs that maintain TRM or to all TOs. |
| **Response**: The SDT reviewed the VSLs and concludes that they appropriately minimize the discretion of the enforcement entity. If in future comments on standards you could be more specific, that would aid the team in addressing your concerns.<br><br>The entire standard only applies to those Transmission Operators that maintain TRM and because this is specified in the applicability, the standard did not reiterate this in the requirements. | | | |
| Tucson Electric Power Co. | 1 | Affirmative | TEP supports proposed WECC Team remedial language clarifying VSL severity level. |
| **Response**: The SDT does not have the WECC team remedial language, and therefore cannot comment on it. | | | |
| Ameren Services Company | 3 | Negative | Ameren would like to thank the SDT for the considerable effort invested in drafting this standard. However, Ameren cannot support this version of MOD-008-1.<br>Applicability: The Transmission Service Provider not the Transmission Operator should be responsible for TRM methodology. This is especially true when the Transmission Service Provider determines TRM for the transmission systems of several Transmission Operators as would occur in an RTO/ISO such as the MISO.<br><br>Is TRM a reliability parameter or a market parameter? While the concepts of uncertainty and sensitivity analysis are inherent in reliability planning TRM as a metric has not been previously defined in the planning process. TRM has been applied in sale of open access transmission system to limit exposure to oversubscription of transmission service. As such TRM should be the responsibility of the Transmission Service Provider. That said we are aware that the oversubscription of transmission service can lead to reliability problems.<br><br>The Transmission Service Provider, Transmission Operator, Planning Coordinator, and Transmission Planner should coordinate and cooperate in developing the TRM methodology. |

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| | | | TRM is applicable in the Operating Time Horizon and the one-year and beyond horizon |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structure; however, we are required to pick a single entity as responsible for this task.<br><br>The SDT believes TRM is a reliability parameter, as the Transmission Operator may expect it to be available as one of his or her tools to manage the reliability of the system and respond to situations outside expected conditions.<br><br>The SDT concurs that oversubscription can lead to reliability problems.<br><br>Developing requirements that require collaboration are difficult, as it can be challenging to discover who is not complying. For example, if MISO and Ameren were unable to come to agreement on development of a TRM methodology, should both entities be sanctioned for not meeting the TRM requirements? NERC has attempted to address this through allowing the use of Joint Registration Organizations, where a MISO/Ameren collaboration would be sanctioned as a single entity, and then the JRO would be responsible for determining how to allocate those sanctions among participants in the JRO.<br><br>With regard to the Time Horizons used in compliance (which are generally used to indicate how much time is available for mitigating a violation to the requirements), the SDT believes the correct horizon is Operations Planning. | | | |
| City Public Service of San Antonio | 3 | Negative | I cannot vote for this standard as written. It needs to acknowledge definitive alternatives to ATC for regions or markets such as ERCOT where transmission service markets are not used. |
| **Response**: If ERCOT does not utilize TRM, then this standard does not apply. | | | |
| Constellation Energy | 3 | Affirmative | Greater standardization in the determination of TRM and monitoring of the on-going appropriateness of the amount set aside for TRM is required. |
| **Response**: The SDT did not believe that it could, at this time, define a single methodology for TRM without arbitrarily affecting either reliability, market access or both. The SDT encourages entities to submit requests for future work to be considered as part of NERC's annual standards planning process. | | | |
| FirstEnergy Solutions | 3 | Affirmative | FirstEnergy Corp. appreciates the hard work of the Standard Drafting Team on the challenging task of reorganizing and enhancing the verbiage of the IROL requirements. We vote AFFIRMATIVE to standard IRO-008-1 and ask that the SDT consider our enclosed comments. Comments on EOP-001, IRO-002, IRO-004, IRO-005, TOP-003, TOP-005, and TOP-006: General "The Violation Risk Factors should be added to the text of all of the standards. IRO-004 - VSL table shows "R7" instead of "R1" IRO-005 - Several Measures reference the incorrect requirement numbers TOP-003 - R4 — There is no measure associated with this requirement - Measures do not include evidence of "planning" of |

| Entity | Segment | Vote | Comment |
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| | | | scheduled outages per the requirements - VSL for R3 and R4 are incorrect and reference the wrong entity per the requirements |
| **Response**: The SDT does not believe these comments are related to MOD-008. | | | |
| Lincoln Electric System | 3 | Negative | LES is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task. | | | |
| Wisconsin Public Service Corp. | 3 | Negative | The Transmission Service Provider should be the responsible entity for MOD-008, not the Transmission Operator. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task. | | | |
| Alliant Energy Corp. Services, Inc. | 4 | Negative | We believe the Transmission Service Provider should be the responsible entity. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task. | | | |
| Public Utility District No. 1 of Douglas County | 4 | Negative | We have not had sufficient time to review the effects of this change and coordinate it with others in our region. |
| **Response**: The SDT believes that significant time has been allowed for entities to review and comment on the standard. | | | |
| WPS Resources Corp. | 4 | Negative | Requirement R3. The TRMID document should be made available to all users, owners, and operators. That is, the TRMID should be publicly available. |
| **Response**: The North American Energy Standards Board (NAESB) is responsible for developing business practices related to public availability of information to support commercial needs. The SDT believes it is NAESB intention to require the disclosure of the TRMID on the OASIS. The NERC standard is related only to reliability, and there is no reliability need for public posting. | | | |
| Constellation Generation Group | 5 | Negative | Greater standardization in the determination of TRM and monitoring of the on-going appropriateness of the amount set aside for TRM is required then this standard provides. |

| Entity | Segment | Vote | Comment |
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| | | | TRM seems to be applied only at certain times by certain TPs. For example, one large TP in the South applies TRM only when an entity is looking for long term transmission service outside an 18 month window. That is, if the transmission service is for a year but the year begins and ends within the next 18 months, TRM isn't applied. This causes a very significant difference in study results. Others apply it differently. This type of item should be standardized. |
| **Response**: The SDT did not believe that it could, at this time, define a single methodology for TRM without arbitrarily affecting either reliability, market access or both. The SDT encourages entities to submit requests for future work to be considered as part of NERC's annual planning process. The MOD standards do require that TRM and other factors of TTC/TFC be applied consistently by an entity so that all users of their system are treated equally. | | | |
| Electric Power Supply Association | 5 | Negative | Greater standardization is required with the standard as drafted. Determination of TRM and monitoring of the associated with the ongoing appropriateness of the amounts set aside for TRM is required to achieve the needed standardization. |
| **Response**: The SDT did not believe that it could, at this time, define a single methodology for TRM without arbitrarily affecting either reliability, market access or both. The SDT encourages entities to submit requests for future work to be considered as part of NERC's annual planning process. | | | |
| FirstEnergy Solutions | 5 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-008 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-008 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent |

| Entity | Segment | Vote | Comment |
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| | | | to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-008 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - All Requirements (R1 through R5) Additional Comments: Applicability Section - The applicability states "Transmission Operators that maintain TRM" and all requirements of the standard are applicable to the TOP in regards to preparing and maintaining a TRM Implementation Document (TRMID), distributing the TRMID to other interested parties, calculating TRM consistent with the TRMID, etc. It is unclear to FE what requirements are placed upon a Transmission Operator that DOES NOT maintain TRM. A TOP who does not maintain TRM could be interpreted one of two ways: 1) For a given TOP footprint TRM is not withheld in calculating ATC 2) TRM is withheld for the TOP footprint, but the TOP does not determine or calculate the TRM value withheld. If the appropriate interpretation is as described in item 1) above, it begs the question if this is a needed reliability standard. If TRM is truly a reliability need, it can not be optional for any TOP service area. If the latter, item 2 and FE's understanding, is the correct interpretation, then FE's position on responsibility remains that that the applicability of this standard should rest with the entity performing the calculation of TRM which in many areas of the country is the TSP organization. Since the SDT has elected to not make a change in this regard we are requesting the aforementioned variance for the MISO RTO area. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. The SDT believes the transfer of responsibility described within the MISO Transmission Owners Agreement would be an effective way to delegate this task to a Transmission Service Provider through the registration of a Joint Registration Organization. To the extent an entity variance is desired, First Energy and/or MISO would need to submit a SAR to request the variance. The commenter is correct that ideally a variance would be considered in the SAR process and throughout the standard development process; however, no one has yet requested a variance through a SAR (or incorporated the request into one of the existing SARs during their development), and at this time the drafting team can not add a variance and still meet the deadline established by NERC and FERC for this revision of the standard.<br><br>Regarding the applicability of the standard, the entire standard only applies to those Transmission Operators that operate their system with the assumption that some transmission capacity margin has been withheld from commercial use to address the reliability threats listed in R1. The SDT does not believe that TRM is required for all entities; entities that have reviewed the risks listed in R1 and determined that they can manage those risks through other means (e.g., demand response, operating guides, etc…) are not required to maintain TRM. | | | |
| Lincoln Electric System | 5 | Negative | LES is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission |

| Entity | Segment | Vote | Comment |
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| | | | Service Provider. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task. | | | |
| AEP Marketing | 6 | Affirmative | AEP has a concern because the standard appears to have an internal ambiguity. The applicability states “Transmission Operators that maintain TRM" however, R1 requires that “Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) ...." In the context of R1, it unclear what requirements are placed upon Transmission Operators that DOES NOT maintain TRM. In addition, the Purpose statement implies that TRM is used as a real-time operation value. It is not. |
| **Response**: The entire standard only applies to those Transmission Operators that maintain TRM and because this is specified in the applicability, the standard did not reiterate this in the requirements. With regard to the use of TRM as a real-time operation value, the SDT believes that while the TRM may not be explicitly scheduled, the capacity withheld as a margin may be used in real-time (e.g., if load forecast is higher than expected, then some of the margin may be used to support the additional internal generation needed to serve that load). | | | |
| Barry Green Consulting Inc. | 6 | Negative | Greater standardization in the determination of TRM and monitoring of the on-going appropriateness of the amount set aside for TRM is required. |
| **Response**: The SDT did not believe that it could, at this time, define a single methodology for TRM without arbitrarily affecting either reliability, market access or both. The SDT encourages entities to submit requests for future work to be considered as part of NERC’s annual planning process. | | | |
| Constellation Energy Commodities Group | 6 | Negative | Greater standardization in the determination of TRM and monitoring of the ongoing appropriateness of the amount set aside for TRM is required. |
| **Response**: The SDT did not believe that it could, at this time, define a single methodology for TRM without arbitrarily affecting either reliability, market access or both. The SDT encourages entities to submit requests for future work to be considered as part of NERC’s annual planning process. | | | |
| FirstEnergy Solutions | 6 | Negative | FirstEnergy Corp. (FE) appreciates the hard work put forth by the NERC ATC/CBM/TRM standard drafting team (SDT). However, based on difficulties of efficiently and effectively implementing the proposed MOD-008 standard within the Midwest ISO (MISO) footprint, FE is voting NEGATIVE to the standard as written. In prior comment periods, FE has indicated its concerns with requirements assigned to NERC registered entity classifications that apply to FE, but in actuality are performed by the MISO. The SDT has not changed its position and has indicated that FE could delegate responsibility to MISO. However, as previously stated, FE believes a standard should not be written in a way that would knowingly require delegation agreements for a large number of responsible entities. Therefore, in order for FE |

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| | | | to support this standard, we request that the SDT work with MISO and its member companies to complete a regional variance for the MISO regional transmission organization and include it within the standard as a Regional Difference. A variance is needed to explain the MOD-008 requirements that describe tasks which have been transferred by the MISO member transmission companies to the MISO organization. This transfer of responsibility is described in the MISO Transmission Owners Agreement and Attachment C of the MISO Open Access Transmission and Energy Market Tariff. It is FE's opinion that an Entity Variance as described in the NERC Reliability Standards Development Procedure is the appropriate mitigation measure and that including the variance with the initial development of the standard is appropriate per the NERC standard development procedure. As described in the procedure, "Variances should be identified and considered when a SAR is posted for comment. Variances should also be considered in the drafting of a standard, with the intent to make any necessary variances a part of the initial development of a standard. The public posting allows for all impacted parties to identify the requirements of a NERC reliability standard that might require a variance." FE believes it is important to complete and include the MISO variance in conjunction with the drafting of the MOD-008 standard. FE requests the variance to cover TOP tasks as described in the following requirements: - All Requirements (R1 through R5) Additional Comments: Applicability Section - The applicability states "Transmission Operators that maintain TRM" and all requirements of the standard are applicable to the TOP in regards to preparing and maintaining a TRM Implementation Document (TRMID), distributing the TRMID to other interested parties, calculating TRM consistent with the TRMID, etc. It is unclear to FE what requirements are placed upon a Transmission Operator that DOES NOT maintain TRM. A TOP who does not maintain TRM could be interpreted one of two ways: 1) For a given TOP footprint TRM is not withheld in calculating ATC 2) TRM is withheld for the TOP footprint, but the TOP does not determine or calculate the TRM value withheld. If the appropriate interpretation is as described in item 1) above, it begs the question if this is a needed reliability standard. If TRM is truly a reliability need, it can not be optional for any TOP service area. If the latter, item 2 and FE's understanding, is the correct interpretation, then FE's position on responsibility remains that that the applicability of this standard should rest with the entity performing the calculation of TRM which in many areas of the country is the TSP organization. Since the SDT has elected to not make a change in this regard we are requesting the aforementioned variance for the MISO RTO area. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. The SDT believes the transfer of responsibility described within the MISO Transmission Owners Agreement would be an effective way to delegate this task to a Transmission Service Provider through the | | | |

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| registration of a Joint Registration Organization. To the extent an entity variance is desired, First Energy and/or MISO would need to submit a SAR to request the variance. The commenter is correct that ideally a variance would be considered in the SAR process and throughout the standard development process; however, no one has yet requested a variance through a SAR (or incorporated the request into one of the existing SARs during their development), and at this time the drafting team can not add a variance and still meet the deadline established by NERC and FERC for this revision of the standard.<br><br>Regarding the applicability of the standard, the entire standard only applies to those Transmission Operators that operate their system with the assumption that some transmission capacity margin has been withheld from commercial use to address the reliability threats listed in R1. The SDT does not believe that TRM is required for all entities; entities that have reviewed the risks listed in R1 and determined that they can manage those risks through other means (e.g., demand response, operating guides, etc…) are not required to maintain TRM. | | | |
| Lincoln Electric System | 6 | Negative | LES is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. | | | |
| Volkmann Consulting | 8 | Negative | This standard does not show the applicability to the Transmission Service Provider. In RTOs the TSP is responsible for calculating and maintaining TRM. Delegation agreements can cover this. However, with the larger portion of the Eastern Interconnection covered by regional tariffs and TSP operation, this standard should speak directly to the TSP responsibilities |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task. | | | |
| Electric Reliability Council of Texas, Inc. | 10 | Abstain | Although the Applicability Section is clear, some Requirements and Measures contain no clear applicability only to those Transmission Operators that maintain TRM in their transmission system and market operations. |
| **Response**: The entire standard only applies to those Transmission Operators that maintain TRM and because this is specified in the applicability, the standard did not reiterate this in the requirements. | | | |
| Midwest Reliability Organization | 10 | Negative | The MRO is concerned with the Transmission Operator being the responsible entity for MOD-008. We believe that the responsible entity for these requirements should be the Transmission Service Provider. |
| **Response**: The SDT believes the Functional Model indicates that TRM should be established by the Transmission Operator. While many entities may have delegated this responsibility to Transmission Service Providers through implementation of regional transmission service, the SDT does not believe this alone changes the responsibilities established. Based on the most recent comment period, the majority of the commenters supported the Transmission Operator as the appropriate entity. The SDT realized this may not be a perfect fit for all structures; however, we are required to pick a single entity as responsible for this task. | | | |

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Standards Announcement

## Ballot Pools and Pre-ballot Windows Open
## June 20–July 21, 2008

**Now available at: https://standards.nerc.net/BallotPool.aspx**

### Ballot Pools and Pre-ballot Windows for IRO-008-1, IRO-009-1, and IRO-010-1

The following Interconnection Reliability Operating Limit (IROL) standards, implementation plan, and a report identifying how the drafting team addressed relevant directives from FERC Order 693 are posted for a 30-day, pre-ballot review starting **June 20, 2008**:

- IRO-008-1 — Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-009-1 — Reliability Coordinator Actions to Operate within IROLs
- IRO-010-1 — Reliability Coordinator Data Specification and Collection

These standards require the Reliability Coordinator to take actions to keep the bulk electric system operating within IROLs.

There are three separate ballot pools for this set of IROL standards — and any member of the Registered Ballot Body may join as many or as few of the ballot pools as desired — a member wanting to ballot all three of the IROL standards must join all three of the ballot pools. The ballot for each of the IROL standards includes the retirement or revision of associated requirements from some already approved standards as identified in the table below. The IROL implementation plan contains the justification for the recommended retirements and revisions.

| Three Ballots for IROL Standards | | |
|---|---|---|
| Ballot Pool (List Server) | Ballot for New Standard | Includes Modifications to Associated Approved Standards |
| IROL Standard — IRO-008_in<br>bp-IRO-008_in@nerc.com | IRO-008 | IRO-004-1 — RC – Operations Planning<br>▪ Retire R1 and R2 |
| IROL Standard — IRO-009_in<br>bp-IRO-009_in@nerc.com | IRO-009 | EOP-001-0 — Emergency Operations Planning<br>▪ Retire R2 |
| | | IRO-004-1 — RC – Operations Planning<br>▪ Retire R3 and R6 |
| | | IRO-005-2 — RC – Current Day Operations<br>▪ Retire R3, R5, R16, R17;<br>▪ Modify R9, R13 and R14 |
| IROL Standard — IRO-010_in<br>bp-IRO-010_in@nerc.com | IRO-010 | IRO-002-1 — RC – Facilities<br>▪ Retire R2 |
| | | IRO-004-1 — RC – Operations Planning<br>▪ Retire R4, R5 |
| | | IRO-005-2 — RC – Current Day Operations<br>▪ Retire R2 |

| | | |
|---|---|---|
| | | TOP-003-0 — Planned Outage Coordination<br>▪ Modify R1.2 |
| | | TOP-005-1 — Operational Reliability Information<br>▪ Retire R1, R1.1 |
| | | TOP-006-1 — Monitoring System Conditions<br>▪ Modify R4 |

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server.[1]" (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The ballot pools will remain open up until **8 a.m. (EDT), Monday, July 21, 2008**.

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### Now available at: https://standards.nerc.net/BallotPool.aspx

### Five Pre-ballot Windows and Ballot Pools for Project 2006-07 — ATC/TTC and CBM/TRM

The following standards related to the determination of Available Transfer Capability (ATC), Total Transfer Capability (TTC), and Transmission Reliability Margin (TRM) and associated implementation plans, are posted for a 30-day, pre-ballot review beginning **June 20, 2008**:

- MOD-001 — Available Transfer Capability
- MOD-008 — Transmission Reliability Margin
- MOD-028 — Area Interchange Methodology
- MOD-029 — Rated System Path Methodology
- MOD-030 — Flowgate Methodology

This set of ATC-related standards requires consistency in the calculation and documentation of TRM, TTC, AFC, and ATC.

Note that there is another standard in this set, MOD-004-1 — Capacity Benefit Margin (CBM), that is still undergoing revisions and is not ready for ballot. The Standards Committee considered whether to wait until the revisions to MOD-004-1 were complete before moving the entire set of six standards forward to ballot. The committee concluded that the interests of NERC and its stakeholders are best served by proceeding with the ballot for the five standards that are ready. Since there are approved standards in place that address CBM, the five new ATC-related standards can be implemented effectively without the new MOD-004-1.

There are five separate ballot pools for this set of ATC standards — and any member of the Registered Ballot Body may join as many or as few of the ballot pools as desired — a member wanting to ballot all five of the ATC-related standards must join all five of the ballot pools. (Note: these are **new ballot pools** — the ballot pools used to conduct the ATC-related ballots that took place earlier this year have been retired.)

The ballot for each of the standards includes the retirement of associated approved standards as identified in the table below. The implementation plans contain the justification for the recommended retirements.

| Five Ballots for ATC Standards | | |
|---|---|---|
| Standard | Ballot Pool<br>(List Server) | Ballot Includes Retirement of Associated Approved Standards |
| MOD-001-1<br>Available Transfer Capability | ATC et al Standards — MOD-001<br>bp-MOD-001_R1_in@nerc.com | MOD-001-0<br>FAC-012-1, FAC-013-1 |

| | | |
|---|---|---|
| MOD-008-1<br>Transmission Reliability Margin | ATC et al Standard — MOD-008<br>bp-MOD-008_R1_in@nerc.com | MOD-008-0, MOD-009-0 |
| MOD-028-1<br>Area Interchange Methodology | ATC et al Standard — MOD-028<br>bp-MOD-028_R1_in@nerc.com | FAC-012-1, FAC-013-1 |
| MOD-029-1<br>Rated System Path Methodology | ATC et al Standard — MOD-029<br>bp-MOD-029_R1_in@nerc.com | FAC-012-1, FAC-013-1 |
| MOD-030<br>Flowgate Methodology | ATC et al Standard — MOD-030<br>bp-MOD-030_R1_in@nerc.com | FAC-012-1, FAC-013-1 |

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## Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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| | | IRO-004-1 — RC – Operations Planning<br>▪ Retire R4, R5 |
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| | | |
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| | | |
|---|---|---|
| MOD-008-1<br>Transmission Reliability Margin | ATC et al Standard — MOD-008<br>bp-MOD-008_R1_in@nerc.com | MOD-008-0, MOD-009-0 |
| MOD-028-1<br>Area Interchange Methodology | ATC et al Standard — MOD-028<br>bp-MOD-028_R1_in@nerc.com | FAC-012-1, FAC-013-1 |
| MOD-029-1<br>Rated System Path Methodology | ATC et al Standard — MOD-029<br>bp-MOD-029_R1_in@nerc.com | FAC-012-1, FAC-013-1 |
| MOD-030<br>Flowgate Methodology | ATC et al Standard — MOD-030<br>bp-MOD-030_R1_in@nerc.com | FAC-012-1, FAC-013-1 |

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# Standard Authorization Request Form

| | |
|---|---|
| Title of Proposed Standard | Flowgate Methodology |
| Request Date | August 8, 2008 |

| **SAR Requester Information** | | **SAR Type** (*Check a box for each one that applies.*) | |
|---|---|---|---|
| Name | Duke Energy | ☐ | New Standard |
| Primary Contact | Laura Lee | ☒ | Revision to existing Standard |
| Telephone<br>Fax | 704-382-3625 | ☐ | Withdrawal of existing Standard |
| E-mail | llee@duke-energy.com | ☐ | Urgent Action |

**Purpose**

To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

**Industry Need**

Entities have proposed methods through which flowgates can be analyzed in a reliable manner other than those included in MOD-030-01. This SAR proposes modifications to the standard such that those methods can be accommodated within the standard.

**Brief Description**

Requirements 2 and 11 of MOD-030-01 will be modified.

**Detailed Description**

Modify R2.1 to make it clear that if any limiting elements or Contingencies are already protected by another Flowgate, then no new Flowgates need to be established for such limiting elements or Contingencies. Modify 2.1 such that limits are placed around flowgates added because of the exercise of an Interconnection-wide Congestion Management procedure. Modify the R2.1 so that it is clear that temporary flowgates are not required to be incorporated into the list of flowgates for which AFC is determined.

Modify R11 to remove references to TFC and TTC, since there are multiple ways to determine TTC from TFC and FERC has not mandated the creation of a single method.

Make conforming changes to the Measures and Compliance elements of the standard to support the above requirements.

Make any other changes as necessary to support the above requirements.

***Reliability Functions***

| The Standard will Apply to the Following Functions *(Check box for each one that applies.)* | | |
|---|---|---|
| ☐ | Regional Reliability Organization | Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions. |
| ☐ | Reliability Coordinator | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view. |
| ☐ | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time. |
| ☐ | Interchange Authority | Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas. |
| ☐ | Planning Coordinator | Assesses the longer-term reliability of its Planning Coordinator Area. |
| ☐ | Resource Planner | Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area. |
| ☐ | Transmission Planner | Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area. |
| ☒ | Transmission Service Provider | Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff). |
| ☐ | Transmission Owner | Owns and maintains transmission facilities. |
| ☒ | Transmission Operator | Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area. |
| ☐ | Distribution Provider | Delivers electrical energy to the End-use customer. |
| ☐ | Generator Owner | Owns and maintains generation facilities. |
| ☐ | Generator Operator | Operates generation unit(s) to provide real and reactive power. |
| ☐ | Purchasing-Selling Entity | Purchases or sells energy, capacity, and necessary reliability-related services as required. |
| ☐ | Market Operator | Interface point for reliability functions with commercial functions. |
| ☐ | Load-Serving Entity | Secures energy and transmission service (and reliability-related services) to serve the End-use Customer. |

***Reliability and Market Interface Principles***

| **Applicable Reliability Principles** *(Check box for all that apply.)* | |
|---|---|
| ☒ | 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☒ | 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☐ | 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented. |
| ☐ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems. |
| ☐ | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☒ | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis. |
| ☐ | 8. Bulk power systems shall be protected from malicious physical or cyber attacks. |

| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box.)* |
|---|
| 1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

***Related Standards***

| Standard No. | Explanation |
|---|---|
| MOD-001-01 | Parent standard to this standard |
| MOD-030-01 | Earlier version of the standard. |
| | |
| | |

***Related SARs***

| SAR ID | Explanation |
|---|---|
| | Parent SAR to this SAR |
| | Supplemental SAR to the above SAR |
| | |
| | |
| | |
| | |
| | |
| | |

***Regional Variances***

| Region | Explanation |
|---|---|
| ERCOT | |
| FRCC | |
| MRO | |
| NPCC | |
| SERC | |
| RFC | |
| SPP | |
| WECC | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SC authorized posting the concurrent posting of the SAR and proposed standard on August 8, 2008.
2. SDT posted SAR and first draft of MOD-030-2 for a 45-day comment period from August 12, 2008 through September 24, 2008.

**Description of Current Draft:**

This is the first draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments from the initial ballot of MOD-030-1 and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Respond to Comments. | To be determined |
| 2. Posting for 30-day Pre-Ballot Review. | To be determined |
| 3. Initial Ballot. | To be determined |
| 4. Respond to comments. | To be determined |
| 5. Recirculation ballot. | To be determined |
| 6. Board adoption. | To be determined |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-02**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.

   **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.

5. **Proposed Effective Date:** The date upon which MOD-030-01 is currently scheduled to become effective.

## B. Requirements

**R1.** The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in AFC calculations including:

**R1.2.1.** Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Include Flowgates used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated

Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

R2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.1.3. If any limiting elements or Contingencies are already protected by another Flowgate, then no new Flowgates need to be established for such limiting elements or Contingencies.

**R2.1.2.** Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

R2.1.2.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

R2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.2.3. If any limiting elements or Contingencies are already protected by another Flowgate, then no new Flowgates need to be established for such limiting elements or Contingencies.

**R2.1.3.** With the exception of flowgates created to address temporary operating conditions, any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

R2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or

- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.
- The Transmission Operator may utilize distribution factors less than 5% if desired.

R2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

**R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.

**R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

**R2.4.** Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, establish the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider’s area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider’s area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:.

**R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.

**R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

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[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{Fi}$** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**$AFC_{NF}$** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

**R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \ldots PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

**Where:**

**ATC** is the Available Transfer Capability.

**P** is the set of partial Available Transfer Capabilities for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**$PATC_n$** is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

**$AFC_n$** is the Available Flowgate Capability of a Flowgate *n*.

**$DF_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

**M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-030-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)

**M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)

**M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

**M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). |
| R2. | One or more of the following:<br>• The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.<br>• The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3.<br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more | One or more of the following:<br>• The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2.<br>• The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as | One or more of the following:<br>• The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2.<br>• The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in | One or more of the following:<br>• The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2.<br>• The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.<br>• The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a flowgate as described in R2.3. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | than 7 days, but it has not been more than 14 days since the notification (R2.5.1)<br><br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | described in R2.3.<br><br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)<br><br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination. | R2.3.<br><br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. | • The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.<br><br>• The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.<br><br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)<br>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | One or more of the following:<br>• The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks | One or more of the following:<br>• The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks | One or more of the following:<br>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks | One or more of the following:<br>• The Transmission Operator did not update the model per R3.2 for more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than ten weeks<br>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>• The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or more than 3 reservations, whichever is greater.. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | One or more of the following:<br>• The Transmission Service Provider did not use the model provided by the Transmission Operator.<br>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.<br>• The Transmission Service provider did not use AFC provided by a third party. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | greater). | greater). | |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |
| R10 | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. | described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | Transmission Service provider did not calculate for 28 or more calendar days. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11. |

## E. Regional Differences

None identified.

## F. Associated Documents

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 2 | | Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11<br>Made conforming changes to M18 and VSLs for R2 and R11 | Revised |
| | | | |
| | | | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SC authorized posting the concurrent posting of the SAR and proposed standard on August 8, 2008.
2. SDT posted SAR and first draft of MOD-030-2 for a 45-day comment period from August 11, 2008 through September 24, 2008.

**Description of Current Draft:**

This is the first draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments from the initial ballot of MOD-030-1 and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Respond to Comments. | To be determined |
| 2. Posting for 30-day Pre-Ballot Review. | To be determined |
| 3. Initial Ballot. | To be determined |
| 4. Respond to comments. | To be determined |
| 5. Recirculation ballot. | To be determined |
| 6. Board adoption. | To be determined |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-2**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.

   **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.

5. **Proposed Effective Date:** The date upon which MOD-030-01 is currently scheduled to become effective.

## B. Requirements

**R1.** The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in AFC calculations including:

**R1.2.1.** Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Include Flowgates used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated

Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

R2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.1.3. If any limiting elements or Contingencies are already protected by another Flowgate, then no new Flowgates need to be established for such limiting elements or Contingencies.

**R2.1.2.** Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

R2.1.2.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

R2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.2.3. If any limiting elements or Contingencies are already protected by another Flowgate, then no new Flowgates need to be established for such limiting elements or Contingencies.

**R2.1.3.** With the exception of flowgates created to address temporary operating conditions, ~~A~~any limiting Element/Contingency combination at least within its Reliability Coordinator's Area ~~the Transmission model identified in R3.4 and R3.5~~ that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology~~[1]~~.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

R2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.
- The Transmission Operator may utilize distribution factors less than 5% if desired.

R2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

**R2.2.** At a minimum, establish ~~the~~ a list of Flowgates ~~to~~ by creatinge, modifying, or deletinge ~~internal~~ Flowgates definitions ~~-~~at least once per calendar year.

**R2.3.** At a minimum, establish ~~the~~ a list of Flowgates ~~to~~ by creatinge, modifying, or deletinge ~~external~~ Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

**R2.4.** Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, establish the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:.

**R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.

**R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the

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[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

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[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC – ETC_{Fi} – CBM_i – TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{Fi}$** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC – ETC_{Fi} – ETC_{NFi} – CBM_{Si} – TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**$AFC_{NF}$** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

**R11.** When converting Flowgate AFCs to ATCs ~~(and TFCs to TTCs)~~ for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \ldots PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

**Where:**

**ATC** is the Available Transfer Capability ~~(either 'Available' or 'Total')~~.

**P** is the set of partial Available Transfer Capabilities ~~(either available or total)~~ for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[8] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**$PATC_n$** is the partial Available Transfer Capability ~~(either 'Available' or 'Total')~~ for a path relative to a Flowgate *n.*

**$AFC_n$** is the Available Flowgate Capability ~~('Available' or 'Total')~~ of a Flowgate *n*.

**$DF_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

[8] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

**M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-030-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)

**M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)

**M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

**M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs ~~(and TFCs to TTCs)~~ for ATC Paths, it follows the procedure described in R11. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.

- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). |
| R2. | One or more of the following:<br>• The Transmission Operator established its list of ~~internal~~ Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.<br>• The Transmission Operator established its list of ~~external~~ Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a~~n~~ ~~external~~ flowgate as described in R2.3.<br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more | One or more of the following:<br>• The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of ~~internal~~ Flowgates more than three months late, but not more than six months late as described in R2.2.<br>• The Transmission Operator established its list of ~~external~~ Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a~~n~~ ~~external~~ flowgate | One or more of the following:<br>• The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of ~~internal~~ Flowgates more than six months late, but not more than nine months late as described in R2.2.<br>• The Transmission Operator established its list of ~~external~~ Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a~~n~~ ~~external~~ flowgate as | One or more of the following:<br>• The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of ~~internal~~ Flowgates more than nine months late as described in R2.2.<br>• The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.<br>• The Transmission Operator established its list of ~~external~~ Flowgates more than 120 days following a request to create, modify or delete a~~n~~ ~~external~~ flowgate as described in R2.3. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | than 7 days, but it has not been more than 14 days since the notification (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | as described in R2.3.<br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination. | described in R2.3.<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. | • The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.<br>• The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.<br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)<br>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | One or more of the following:<br>• The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks | One or more of the following:<br>• The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks | One or more of the following:<br>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks | One or more of the following:<br>• The Transmission Operator did not update the model per R3.2 for more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than ten weeks<br>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>• The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or more than 3 reservations, whichever is greater.. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | One or more of the following:<br>• The Transmission Service Provider did not use the model provided by the Transmission Operator.<br>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.<br>• The Transmission Service provider did not use AFC provided by a third party. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | greater). | greater). | |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |
| R10 | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. | described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | Transmission Service provider did not calculate for 28 or more calendar days. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs ~~(and/or TFCs to TTCs)~~ described in R11. |

## E. Regional Differences

None identified.

## F. Associated Documents

# Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 2 | | Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11<br>Made conforming changes to M18 and VSLs for R2 and R11 | Revised |
| | | | |
| | | | |

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Standards Announcement

## Two Comment Periods Open
## August 12, 2008

### Comment Period for SAR and MOD-030-2 — Flowgate Methodology (Project 2006-07) Posted for 45-day Comment Period August 12–September 24, 2008

The "ATC" Standard Drafting Team has posted a new SAR, a new proposed version of MOD-030-2 – Flowgate Methodology, and an implementation plan for a 45-day comment period through **September 24, 2008**.

This new version of the standard was developed based on stakeholder comments submitted with the initial ballot of MOD-030-1 conducted July 21–30, 2008. The drafting team's responses to the comments submitted with the ballots for this standard are posted for stakeholder review. MOD-030-1 will continue through the recirculation ballot process at the same time this new version of the standard goes through the standards development process. As envisioned, the new version of MOD-030-2 will be approved by its ballot pool and filed for regulatory approval before MOD-030-1 becomes effective.

Please use this electronic form to submit comments on the SAR, standard and the associated implementation plan.

If you need an off-line, unofficial copy of the questions in the comment form, there is a copy of the comment form posted at the following site:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

Please use only the electronic form to submit comments by **September 24, 2008**. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

### Comment Period for SAR for Credible Multiple Contingencies (Project 2008-05) Posted for 30-day Comment Period August 12–September 10, 2008

Draft 2 of the SAR for Credible Multiple Contingencies is posted for a 30-day comment period through **September 10, 2008**. The revised SAR proposes modifying FAC-011-2 — System Operating Limit Methodology for the Operations Horizon to require:

- The consideration of common mode Contingencies that result in loss of two or more (multiple) elements that are associated with potential IROL conditions, and
- That the System Operating Limit (SOL) methodology addresses the SOLs received from the Planning Authority.

To aid in understanding the revised scope of modifications, the SAR drafting team has posted a red line version of FAC-011-2 with the proposed changes.

Please use this electronic form to submit comments on the SAR.

If you need an off-line, unofficial copy of the questions in the comment form, there is a copy of the comment form posted at the following site:

http://www.nerc.com/filez/standards/Facility_Ratings_Project_2008-05.html

Please use only the electronic form to submit comments by **September 10, 2008**. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

*For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.*

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-030-02, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining AFC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard completely replaces MOD-030-01.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-030 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the date upon which MOD-030-01 is currently scheduled to become effective.

Comments must be submitted by **September 24, 2008.** If you have questions please contact **Andy Rodriquez** at [Andy.Rodriquez@nerc.net](mailto:Andy.Rodriquez@nerc.net) or by telephone at 609.947.3885.

## Background Information

Project 2006-07 was initiated in 2006 to revise the then existing NERC reliability modeling standards to ensure the consistent and transparent calculation, verification, preservation, and use of Total Transfer Capability (TTC)/Available Transfer Capability (ATC)/Available Flowgate Capability (AFC). Project 2006-07 requires specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies and adds requirements for documentation of the methodologies used to coordinate TTC/ATC/AFC. Such changes will enhance the reliable use of the bulk power transmission system without arbitrarily limiting commercial activity.

On February 17, 2007 FERC issued Order 890 which directed, among other things, a number of reforms in the determination of ATC by requiring consistency in how TTC/ATC/AFC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates TTC/ATC/AFC. Then on March 16, 2007 FERC issued Order 693 which provided directives on modifying the NERC standards, including those related to modeling.

During the initial ballot for MOD-030-1, several balloters proposed the following modifications and they are reflected in the SAR and in the modifications to the standard:

- Modify R2.1 to make it clear that if any limiting elements or Contingencies are already protected by another Flowgate, then no new Flowgates need to be established for such limiting elements or Contingencies.
- Modify 2.1 such that limits are placed around flowgates added because of the exercise of an Interconnection-wide Congestion Management procedure.
- Modify the R2.1 so that it is clear that temporary flowgates are not required to be incorporated into the list of flowgates for which AFC is determined.
- Modify R11 to remove references to TFC and TTC, since there are multiple ways to determine TTC from TFC and FERC has not mandated the creation of a single method.
- Make conforming changes to the Measures and Compliance elements of the standard to support the above requirements.

In response to suggestions for these improvements, the drafting team has created the following proposed standard:

**MOD-030-02 – Flowgate Methodology**

Please review the SAR and the proposed standard and then answer the following questions.

**You do not have to answer all questions.**

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

**1.** Do you agree with the SAR’s purpose, scope and applicability?

☐ Yes

☐ No

Comments:

**2.** The drafting team has modified R2.1, R2.2, R2.3, and R11. Do you agree with the proposed changes?

☐ Yes

☐ No

☐ No preference

If “No,” please identify the modifications with which you are concerned and suggest changes to the language. Comments:

**3.** Are you aware of any conflicts between the proposed MOD-030-2 and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☐ No

☐ No preference

If “Yes,” please explain why in the comment area below and provide supporting information. Comments:

**4.** Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed MOD-030-2.

Comments:

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Flowgate:**

1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

**Available Flowgate Capability (AFC):** A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**
2. **Number:** **MOD-030-1**
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
   - **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs)on Flowgates.
   - **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** The Transmission Service Provider shall include in its "Available Transfer Capability Implementation Document" (ATCID). [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in AFC calculations including:

**R1.2.1.** Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Include Flowgates used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated

Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.** Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use first Contingency criteria consistent with those first Contignency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.

2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.3.** Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.
- The Transmission Operator may utilize distribution factors less than 5% if desired.

2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

**R2.2.** At a minimum, establish the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.

**R2.3.** At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

**R2.4.** Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, establish the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence"

representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.

- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:.

**R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider’s area.

**R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider’s area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

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[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{Fi}$** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC – ETC_{Fi} – ETC_{NFi} – CBM_{Si} – TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**$AFC_{NF}$** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

**R11.** When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$TC = \min(P)$$

$$P = \{PTC_1, PTC_2, \ldots PTC_n\}$$

$$\mathrm{PTC_n} = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either 'Available' or 'Total').

**P** is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**$PTC_n$** is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n.*

**$FC_n$** is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

**$DF_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

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[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

**M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-030-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)

**M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)

**M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

**M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, it follows the procedure described in R11. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits

- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). |
| R2. | One or more of the following:<br>• The Transmission Operator established its list of internal Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.<br>• The Transmission Operator established its list of external Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete an external flowgate as described in R2.3.<br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more | One or more of the following:<br>• The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of internal Flowgates more than three months late, but not more than six months late as described in R2.2.<br>• The Transmission Operator established its list of external Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete an external flowgate | One or more of the following:<br>• The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of internal Flowgates more than six months late, but not more than nine months late as described in R2.2.<br>• The Transmission Operator established its list of external Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete an external flowgate as | One or more of the following:<br>• The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of internal Flowgates more than nine months late as described in R2.2.<br>• The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.<br>• The Transmission Operator established its list of external Flowgates more than 120 days following a request to create, modify or delete an external flowgate as described in R2.3. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | than 7 days, but it has not been more than 14 days since the notification (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | as described in R2.3.<br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination. | described in R2.3.<br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. | • The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.<br>• The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.<br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)<br>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | One or more of the following:<br>• The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks | One or more of the following:<br>• The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks | One or more of the following:<br>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks | One or more of the following:<br>• The Transmission Operator did not update the model per R3.2 for more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than ten weeks<br>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>• The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater.. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or more than 3 reservations, whichever is greater.. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | One or more of the following:<br>• The Transmission Service Provider did not use the model provided by the Transmission Operator.<br>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.<br>• The Transmission Service provider did not use AFC provided by a third party. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | greater). | greater). | |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |
| R10 | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>▪ For Monthly, the values | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. | described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | Transmission Service provider did not calculate for 28 or more calendar days. |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs (and/or TFCs to TTCs) described in R11. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 3–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Flowgate:**

1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

**Total Flowgate Capability (TFC):** The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

**Available Flowgate Capability (AFC):** A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.

**Power Transfer Distribution Factor (PTDF):** In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system F~~f~~acilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer .

**Outage Transfer Distribution Factor (OTDF):** In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system F~~f~~acilities removed from service (outaged).

**Flowgate Methodology:** The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).

## A. Introduction

1. **Title:** **Flowgate Methodology**

2. **Number:** **MOD-030-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.1** Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available ~~Transfer~~ Flowgate Capabilities (A~~T~~FCs) ~~for ATC Paths~~on Flowgates.

   **4.1.2** Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates~~ATCs for ATC Paths~~.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID). [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.

**R1.2.** The following information on how source and sink for transmission service is accounted for in AFC calculations including:

**R1.2.1.** Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.

**R1.2.2.** Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.

**R1.2.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.2.4.** If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.

**R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Include~~Identify~~ Flowgates used in the AFC process based, at a minimum, on the following criteria:

**R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

2.1.1.1. Use first Contingency ~~assumptions~~ criteria consistent with those first Contingenc~~ies~~y criteria used in planning of operations~~operations studies and planning studies~~ for the applicable time periods, including use of Special Protection Systems.

2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.** Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

2.1.2.1. Use first Contingency ~~assumptions~~ criteria consistent with those first Contignenc~~ies~~y criteria used in planning of operations~~operations studies and planning studies~~ for the applicable time periods, including use of Special Protection Systems.

2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.3.** Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

2.1.4.1. T~~If t~~he coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

2.1.4.2. T~~If t~~he limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

**R2.2.** At a minimum, establish the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.

**R2.3.** At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

**R2.4.** Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, establish the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and F~~f~~acilities161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the ~~period calculated~~applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.~~3~~4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ($ETC_{Fi}$) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.1.2.** Unit commitment and ~~dispatch~~ Dispatch ~~order~~Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage[1] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:.

**R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

**R6.2.2.** Unit commitment and ~~dispatch~~ Dispatch ~~order~~Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.

**R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.

**R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage[2] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[3] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R6.7.** The impact of other firm services determined by the Transmission Service Provider.

**R7.** When calculating the impact of ETC for non-firm commitments ($ETC_{NFi}$) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

[1] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[2] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[3] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.

**R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage[4] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.

**R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage[5] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers~~,~~ and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage[6] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

**R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

**R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC – ETC_{Fi} – CBM_i – TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

**Where:**

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

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[4] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[5] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

[6] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{Fi}$** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC – ETC_{Fi} – ETC_{NFi} – CBM_{Si} – TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**$AFC_{NF}$** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

**R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.~~3~~2, R3.~~4~~3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

**R11.** When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$TC = \min(P)$$

$$P = \{PTC_1, PTC_2, \ldots PTC_n\}$$

$$PTC_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either 'Available' or 'Total').

**P** is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage[7] used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**$PTC_n$** is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n.*

**$FC_n$** is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

**$DF_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in ~~that are to be considered in~~ AFC calculations. (R1)

**M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)

**M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)

**M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)

**M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

**M6.** The Transmission Operator shall provide evidence (such as logs) that it ~~updated~~ established the TFCs for each Flowgate in accordance with the timing defined in R2.5~~at least once per calendar year~~. (R2.5)

**M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

[7] A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)

**M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)

**M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)

**M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)

**M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)

**M13.** The Transmission Service Provider~~TSP~~ ~~must be capable of~~shall demonstrate~~ing~~ ~~that for any calculation of firm ETC made in the previous sixty days, the Transmission Service Provider can~~compliance with R6 by recalculating~~e~~ ~~the individual value of the~~ firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate ~~this~~ the specified value for the designated ~~hour~~time period. The data used must meet the requirements specified in ~~the standard~~MOD-030-1 and the ATCID.~~,~~ To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is ~~and the audited value must be~~ within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC~~demonstrated result~~. (R6)

**M14.** The Transmission Service Provider~~TSP~~ ~~must be capable of~~shall demonstrate~~ing~~ ~~that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can~~compliance with R7 by recalculating~~e~~ ~~the individual value of the~~ non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate ~~this~~ the specified value for the designated ~~hour~~time period. The data used must meet the requirements specified in the standard and the ATCID. ~~, and the audited value must be~~ To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC~~demonstrated result~~. (R7)

**M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

**M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated ~~ATC~~ AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, it~~that the determination of Transfer Capabilities~~ follows the procedure described in R11. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to ~~to~~ determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in ~~with~~ R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.

- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete. | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br>**OR**<br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing). |
| R2. | One or more of the following:<br>• The Transmission Operator established its list of internal Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.<br>~~OR~~<br>• The Transmission Operator established its list of external Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete an external flowgate as described in R2.3.<br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more | One or more of the following:<br>• The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.<br>~~OR~~<br>• The Transmission Operator established its list of internal Flowgates more than three months late, but not more than six months late as described in R2.2.<br>~~OR~~<br>• The Transmission Operator established its list of external Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete an external flowgate | One or more of the following:<br>• The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.<br>~~OR~~<br>• The Transmission Operator established its list of internal Flowgates more than six months late, but not more than nine months late as described in R2.2.<br>~~OR~~<br>• The Transmission Operator established its list of external Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete an | One or more of the following:<br>• The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.<br>• The Transmission Operator established its list of internal Flowgates more than nine months late as described in R2.2.<br>~~OR~~<br>• The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.<br>~~OR~~<br>• The Transmission Operator established its list of external Flowgates more than 120 |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | than 7 days, but it has not been more than 14 days since the notification (R2.5.1)<br><br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. | as described in R2.3.<br><br>~~OR~~<br><br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.<br><br>• The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)<br><br>~~OR~~<br><br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination. | external flowgate as described in R2.3.<br><br>~~OR~~<br><br>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.<br><br>~~OR~~<br><br>• The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)<br><br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. | days following a request to create, modify or delete an external flowgate as described in R2.3.<br><br>~~OR~~<br><br>• The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.<br><br>~~OR~~<br><br>~~The Transmission Operator has not updated its list of internal Flowgates for two or more consecutive years.~~<br><br>~~OR~~<br><br>• The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.<br><br>~~OR~~<br><br>• The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)<br><br>~~OR~~ |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | • The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)<br>~~OR~~<br>• The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination. |
| R3. | One or more of the following:<br>• The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks | One or more of the following:<br>• The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks | One or more of the following:<br>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks | One or more of the following:<br>• The Transmission Operator did not update the model per R3.2 for more than 4 calendar days<br>• The Transmission Operator did not update the model for per R3.3 for more than ten weeks<br>~~The Transmission Operator used a Transmission model that had not been updated per the schedule specified in R3.~~<br>~~OR~~<br>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | ~~Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled.~~ | ~~Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled.~~ | ~~Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled.~~ | Transmission or Generator Owner in their Transmission model.<br>~~OR~~<br>• The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.<br>~~OR~~<br>• The Transmission operator did not include in the Transmission ~~model detailed~~ modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.~~at least three contiguous busses of the BES for more than one adjacent Reliability Coordinator area~~.<br>~~Note: A modeling error (a violation of the criteria in R3.1, R3.4, or R3.5) is a single violation, regardless how many times that error has been modeled.~~ |
| R4. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater.. | 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater.. | 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater.. | more than 3 reservations, whichever is greater.. |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. | One or more of the following:<br>• The Transmission Service Provider did not use the model provided by the Transmission Operator.<br>~~OR~~<br>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.<br>~~OR~~<br>• The Transmission Service provider did not use AFC provided by a third party. |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.. | whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | whichever is greater. |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater). |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | not more than 5% of all Flowgates or 1 Flowgate (whichever is greater). | or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater). | Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater). | Flowgates or more than 3 Flowgates (whichever is greater). |
| R10 | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.<br>~~For Hourly, the Transmission Service provider did not calculate for more than 24~~ | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.<br>~~For Hourly, the Transmission Service provider did not calculate for more than 48~~ | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.<br>~~For Hourly, the Transmission Service provider did not~~ | One or more of the following:<br>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.<br>~~For Hourly, the Transmission Service provider did not calculate for more than 96 hours.~~<br>~~**OR**~~ |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | ~~hours but not more than 48 hours.~~<br>~~**OR**~~<br>~~For Daily, the Transmission Service provider did not calculate for more than 7 calendar days but not more than 14 calendar days.~~<br>~~**OR**~~<br>~~For Monthly, the Transmission Service provider did not calculate for 31 or more calendar days, but less than 60 calendar days.~~ | ~~hours but not more than 72 hours.~~<br>~~**OR**~~<br>~~For Daily, the Transmission Service provider did not calculate for more than 14 calendar days but not more than 21 calendar days.~~<br>~~**OR**~~<br>~~For Monthly, the Transmission Service provider did not calculate for 60 or more calendar days, but less than 90 calendar days.~~ | ~~calculate for more than 72 hours but not more than 96 hours.~~<br>~~**OR**~~<br>~~For Daily, the Transmission Service provider did not calculate for more than 21 calendar days but not more than 28 calendar days.~~<br>~~**OR**~~<br>~~For Monthly, the Transmission Service provider did not calculate for 90 or more calendar days, but less than 120 calendar days.~~ | ~~For Daily, the Transmission Service provider did not calculate for more than 28 calendar days.~~<br>~~**OR**~~<br>~~For Monthly, the Transmission Service provider did not calculate for 120 or more calendar days.~~ |
| R11. | N/A | N/A | N/A | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs (and/or TFCs to TTCs) ~~determining Transfer Capabilities~~ described in R11. |

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RELIABILITY CORPORATION

# Implementation Plan for Standard MOD-030 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-030 — Flowgate Methodology, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining AFC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard incorporates the following requirements from FAC-012:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board. As such, FAC-012 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-030 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001, MOD-028, MOD-029, and MOD-030) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to

implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Implementation Plan for Standard MOD-030 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-030 — Flowgate Methodology, which describes the Flowgate methodology (previously referred to as the Flowgate Network Response ATC methodology) for determining AFC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard incorporates the following requirements from FAC-012:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).

R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board. As such, FAC-012 is no longer needed and is being retired.

This standard incorporates the following requirements from FAC-013:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013 is no longer needed and is being retired.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-030 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001, MOD-028, MOD-029, and MOD-030) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to

implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Summary of Process Steps Taken Following Posting of the Standards for 30-day Comment

The ATC Standard Drafting Team is developing the ATC-related standards, in part, as a response to FERC Order 890. Order 890 provided specific guidance on the timeliness of this standards development effort. The drafting team has been working to a strict time line to ensure it can file these standards in compliance with the Commission's directives, while also adhering to the NERC Reliability Standards Development Procedure.

As described in Step 8 of NERC's Reliability Standards Development Procedure,

> "Based on the comments received and field testing, the standard drafting team may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the effect or use of the standard."

When reviewing the comments received and considering changes to the standards, the drafting team also considered that any substantive changes to the requirements would require an additional 30-day comment and response period, which would eliminate the possibility of meeting the FERC's submission deadlines. The drafting team carefully weighed the reliability benefit of any changes to the standard, and attempted to limit its modifications to those that clarify or explain, rather than create new requirements or change intent. The changes to the standards made by the drafting team fall into one or more of the following categories:

- Corrections
- Redrafting of language that does not change intent
- Clarifications that better explain intent
- Modifications that change minor details, but not intent
- Modifications to ensure consistency and reduce ambiguity

The drafting team does not believe that any of the changes made to the requirements following the last comment period directly or materially affect the effect or use of the standards, but instead make the standards more clear.

The NERC Standards Committee is a stakeholder group responsible for the oversight of standards development, including evaluation of the responses to comments and any changes to the standards. As described in Step 8 of NERC's Reliability Standards Development Procedure:

> "When the Standards Committee receives a draft standard that is recommended for ballot, the Standards Committee will review the standard and recommendations of the standards process manager to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives and requirements cited in Steps 1 to 8, as applicable; has an implementation plan; and is compatible with other existing standards. If the proposed standard does not pass this review, the Standards Committee shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the Standards

> Committee shall set the proposed standard for ballot as soon as the work flow will accommodate."

NERC's Standards Process Manager presented the changes described above to the Executive Committee of the NERC Standards Committee on June 19, 2008. Following review of the revisions made to the standards, comment responses, and implementation plans, the Standards Committee's Executive Committee determined that the standards had passed the review, and the changes made do not directly or materially affect the effect or use of the standards. The Standards Committee's Executive Committee directed NERC's Standards Process Manager to post the standards for 30-day pre-ballot review and to begin assembling the ballot pools necessary for balloting.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30 Day posting before board adoption. | June 21 ,2008 |
| 8. Board adopts MOD-001-1. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Rated System Path Methodology:** The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

## A. Introduction

1. **Title:** **Rated System Path Methodology**
2. **Number:** **MOD-029-1**
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**
   - **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
   - **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

**R1.1.1.** Includes at least:

R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)

R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)

**R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.

**R1.1.3.** Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.

**R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

**R1.1.5.** Uses Load forecast by Balancing Authority.

**R1.1.6.** Uses Transmission Facility additions and retirements.

**R1.1.7.** Uses Generation Facility additions and retirements.

**R1.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

**R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

**R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

**R2.** The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

**R2.1.1.** When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.

**R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

**R2.1.3.** Uncontrolled separation shall not occur.

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

**R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

**R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

**R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

$\mathbf{NL_F}$ is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$\mathbf{ROR_F}$ is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

$\mathbf{OS_F}$ is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

$\mathbf{NITS_{NF}}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_{NF}}$ is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

**Where**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

**R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)

**M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

**M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

**M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

**M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15

MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)

**M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

**M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30

days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)

- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2) | The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2) | The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2) | The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2) |
| R2 | One or both of the following:<br>• The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include one required item in the study report required in R2.8. | One or both of the following:<br>• The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include two required items in the study report required in R2.8. | One or both of the following:<br>• The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include three required items in the study report required in R2.8. | One or more of the following:<br>• The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator did not apply R2.7.<br>• The Transmission Operator does not include four or more required items in the study report required in R2.8 |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater). |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized. |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC Conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30 Day posting before board adoption. | June 21 ,2008 |
| 8. Board adopts MOD-001-1. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Rated System Path Methodology:** The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

## A. Introduction

1. **Title:** **Rated System Path Methodology**

2. **Number:** **MOD-029-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

**R1.1.1.** Includes at least:

1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (~~e~~Equivalent representation is allowed.)~~.~~

1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (~~e~~Equivalent representation is allowed.)~~.~~

**R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.

**R1.1.3.** Models all generation (may be either a single generator or multiple generators)~~Facilities~~ ~~larger~~ that is greater than 20 MVA at the point of interconnection in the studied area.

**R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

**R1.1.5.** Uses Load forecast by Balancing Authority.

**R1.1.6.** Uses Transmission Facility additions and retirements.

**R1.1.7.** Uses Generation Facility additions and retirements.

**R1.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

**R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

**R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.

**R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

**R2.** The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R2.1.** Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

**R2.1.1.** When modeling normal conditions, ~~do not model any~~all Transmission Elements will be modeled at or ~~above~~ below 100% of ~~its~~ their continuous rating.

**R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

**R2.1.3.** Uncontrolled separation shall not occur.

**R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

**R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

**R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

**R2.5.** The Transmission Operator shall identify when~~Verify that~~ the TTC for the ATC Path being studied ~~does not~~has an adverse~~ly~~ impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. ~~.~~ The Transmission Operator shall include the resolution of this adverse impact in ~~the~~its study report for the ATC Path.

**R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

**R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

**R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

**R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** When calculating ETC for firm Existing Transmission Commitments ($ETC_F$) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

$\mathbf{NL_F}$ is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "s~~S~~afe h~~H~~arbor t~~T~~ariff." ~~accepted by FERC.~~

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$\mathbf{ROR_F}$ is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

$\mathbf{OS_F}$ is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ($ETC_{NF}$) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**$GF_{NF}$** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "s~~S~~afe h~~H~~arbor t~~T~~ariff." ~~accepted by FERC.~~

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

**Where**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_F$** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

**R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks$_{NF}$** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows$_{NF}$** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

## C. Measures

**M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

**M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, ~~used in its ATC calculations,~~ as required in R1. (R1)

**M1.2.** The Transmission model produced must include the areas listed in R1.1.1 ~~1~~ (or an equivalent representation, as described in the requirement) (R1.1)

**M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

**M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

**M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

**M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

**M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

**M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

**M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

**M7.** The Transmission Service Provider ~~must be capable of~~shall ~~demonstrating~~ demonstrate compliance with R5 by ~~that for any calculation of firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate~~ recalculating ~~the individual value of the~~ firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate ~~this~~ the specified value for the designated ~~hour.~~time period. The data used must meet the requirements specified in ~~the standard~~MOD-029-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is ~~, and the audited value must be~~ within +/- 15% or 15 MW, whichever is greater, of the

~~demonstrated~~ originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC~~result~~. (R5)

**M8.** The Tran~~a~~smission Service Provider ~~must be capable of demonstrating~~shall demonstrate compliance with R5 by ~~that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can~~ recalculatinge ~~the individual value of the~~ non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated ~~hour~~time period. The data used must meet the requirements specified in the ~~standard~~ MOD-029 and the ATCID.~~,~~ To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is ~~and the audited value must be~~ within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC~~demonstrated result~~. (R6)

**M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

**M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)

- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. ~~to show compliance with R5 and R6.~~ (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

~~-~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)<br>~~Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~ | The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)<br>~~Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~ | The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)<br>~~Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~ | The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.<br>**OR**<br>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)<br>~~Note: A modeling error (a violation of the criteria in R1) is a single violation, regardless how many times that error has been modeled.~~ |
| R2 | One or ~~more~~both ~~violations below constitutes a single Lower violation of R2~~of the following:<br>• The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include one required item in the study report required in R2.8. | One or ~~more~~both ~~violations below constitutes a single Moderate violation of R2~~of the following:<br>• The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include two required items in the study report required in R2.8. | One or ~~more~~both ~~violations below constitutes a single High violation of R2~~of the following:<br>• The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator does not include three required items in the study report required in R2.8. | One or more ~~violations below constitutes a single Severe violation of R2~~of the following:<br>• The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.<br>• The Transmission Operator did not apply R2.7.<br>The Transmission Operator does not include four or more required items in the study report required |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | ~~N/A~~ | ~~N/A~~ | ~~N/A~~ | in R2.8<br>• ~~The Transmission Operator did not calculate TTC using the process described in R2.~~ |
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater). |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized. |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | 25MW, whichever is greater. | 35MW, whichever is greater. | 45MW, whichever is greater. | |
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | Paths or 1 ATC Path (whichever is greater). | greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | Paths (whichever is greater). |

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# Implementation Plan for Standard MOD-029-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-029-1 – Rated System Path Methodology, which describes the Rated System Path methodology for determining ATC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Retired Standards

FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-029-1 incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-029-1 becomes effective.

FAC-013-1 – Establish and Communicate Transfer Capabilities, includes two requirements. MOD-029-1 incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-029-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-029-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

### Implementation Plan for Standard MOD-029-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-029-1 – Rated System Path Methodology, which describes the Rated System Path methodology for determining ATC.

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There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

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FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-029-1 incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-029-1 becomes effective.

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- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-029-1 becomes effective.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-029-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Summary of Process Steps Taken Following Posting of the Standards for 30-day Comment

The ATC Standard Drafting Team is developing the ATC-related standards, in part, as a response to FERC Order 890. Order 890 provided specific guidance on the timeliness of this standards development effort. The drafting team has been working to a strict time line to ensure it can file these standards in compliance with the Commission's directives, while also adhering to the NERC Reliability Standards Development Procedure.

As described in Step 8 of NERC's Reliability Standards Development Procedure,

> "Based on the comments received and field testing, the standard drafting team may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the effect or use of the standard."

When reviewing the comments received and considering changes to the standards, the drafting team also considered that any substantive changes to the requirements would require an additional 30-day comment and response period, which would eliminate the possibility of meeting the FERC's submission deadlines. The drafting team carefully weighed the reliability benefit of any changes to the standard, and attempted to limit its modifications to those that clarify or explain, rather than create new requirements or change intent. The changes to the standards made by the drafting team fall into one or more of the following categories:

- Corrections
- Redrafting of language that does not change intent
- Clarifications that better explain intent
- Modifications that change minor details, but not intent
- Modifications to ensure consistency and reduce ambiguity

The drafting team does not believe that any of the changes made to the requirements following the last comment period directly or materially affect the effect or use of the standards, but instead make the standards more clear.

The NERC Standards Committee is a stakeholder group responsible for the oversight of standards development, including evaluation of the responses to comments and any changes to the standards. As described in Step 8 of NERC's Reliability Standards Development Procedure:

> "When the Standards Committee receives a draft standard that is recommended for ballot, the Standards Committee will review the standard and recommendations of the standards process manager to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives and requirements cited in Steps 1 to 8, as applicable; has an implementation plan; and is compatible with other existing standards. If the proposed standard does not pass this review, the Standards Committee shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the Standards

> Committee shall set the proposed standard for ballot as soon as the work flow will accommodate."

NERC's Standards Process Manager presented the changes described above to the Executive Committee of the NERC Standards Committee on June 19, 2008. Following review of the revisions made to the standards, comment responses, and implementation plans, the Standards Committee's Executive Committee determined that the standards had passed the review, and the changes made do not directly or materially affect the effect or use of the standards. The Standards Committee's Executive Committee directed NERC's Standards Process Manager to post the standards for 30-day pre-ballot review and to begin assembling the ballot pools necessary for balloting.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

## A. Introduction

1. **Title: Area Interchange Methodology**

2. **Number: MOD-028-1**

3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.

4. **Applicability:**

   **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.

   **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.

**R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.

**R1.3.** Any contractual obligations for allocation of TTC.

**R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.

**R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:

**R1.5.1.** Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation

**R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation

**R1.5.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.5.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

**R2.** When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R3.1.2.** Load forecast for the applicable period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

**R3.2.2.** Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.** When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Use all Contingencies meeting the criteria described in the ATCID.

**R4.2.** Respect any contractual allocations of TTC.

**R4.3.** Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent

Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.

- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

**R5.** Each Transmission Operator shall establish TTC for each ATC Path as defined below: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.

**R5.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R5.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

**R6.** Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

**R6.2.** If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R6.3.** Use (as the TTC) the lesser of:

– The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or

– The sum of Facility Ratings of all ties comprising the ATC Path.

**R6.4.** For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.

[1] The Transmission operator may honor distribution factors less than 5% if desired.

**R7.** The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

**R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

**R8.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NITS_F$** is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_F$** is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R9.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources)

reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_{NF}$** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R10.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

**Where:**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

**R11.** When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**ETC$_{NF}$** is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

**CBM$_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

**TRM$_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks$_{NF}$** are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows$_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

**M4.** Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

**M5.** Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

**M6.** Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

**M7.** Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated

duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)

**M8.** Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)

**M9.** Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

**M10.** The Transmission Service Provider shall demonstrate compliance with R8 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)

**M11.** The Transmission Service Provider shall demonstrate compliance with R9 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC. (R9)

**M12.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)

**M13.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

## D. Compliance

## 1. Compliance Monitoring Process

### 1.1. Compliance Enforcement Authority

Regional Entity.

### 1.2. Compliance Monitoring Period and Reset

Not applicable.

### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R8 and R9 for the most recent 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has an ATCID but it is missing one of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements) | The Transmission Service Provider has an ATCID but it is missing two of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements) | The Transmission Service Provider has an ATCID but it is missing three of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements) | The Transmission Service Provider has an ATCID but it is missing more than three of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements) |
| R2. | The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. | The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. | One or both of the following:<br>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator Area. | One or more of the following:<br>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>• The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator Area.<br>• The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | Areas. |
| R3. | The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. | One or more of the following:<br>• The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.<br>• The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3. |
| R4. | The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater. | The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater. | The Transmission Operator did not model reservations' sources or sinks as described in R5.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater. | One or more of the following:<br>• The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br>• The Transmission Operator did not respect contractual allocations of TTC.<br>• The Transmission Service Provider did not model reservations' sources or sinks as described in R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater.<br>• The Transmission Operator did not use firm reservations to estimate interchange or did not |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | utilize that estimate in the TTC calculation as described in R4.3. |
| R5. | One or more of the following:<br>• The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days<br>• The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month | One or more of the following:<br>• The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days<br>• The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month | One or more of the following:<br>• The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days<br>• The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month | One or more of the following:<br>• The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 16 calendar days<br>• The Transmission Operator did not establish TTCs for use in monthly ATCs during a four or more consecutive calendar month period<br>• The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3 |
| R6. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the process specified in R6. |
| R7. | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.<br>• The Transmission Operator | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.<br>• The Transmission Operator | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.<br>• The Transmission Operator | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination.<br>• The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination. | has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination. | has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination. | daily ATC calculations.<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination.<br>• The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations. |
| R8. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R9. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | more than 25% of the value calculated in the measure or 25MW, whichever is greater. | more than 35% of the value calculated in the measure or 35MW, whichever is greater... | more than 45% of the value calculated in the measure or 45MW, whichever is greater. | |
| R10. | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |
| R11. | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be developed as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Posting for 30-day industry comment. | April 16, 2008 |
| 2. Respond to Comments. | June 20, 2008 |
| 3. Posting for 30-day Pre-Ballot Review. | June 21, 2008 |
| 4. Initial Ballot. | July 21, 2008 |
| 5. Respond to comments. | August 20, 2008 |
| 6. Recirculation ballot. | August 21, 2008 |
| 7. 30-day posting before board adoption. | June 21, 2008 |
| 8. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Area Interchange Methodology:** The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

## A. Introduction

1. **Title: Area Interchange Methodology**
2. **Number: MOD-028-1**
3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.
4. **Applicability:**
   - **4.1.** Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
   - **4.2.** Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- **R1.1.** Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.
- **R1.2.** A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.
- **R1.3.** Any contractual obligations for allocation of TTC.
- **R1.4.** A description of the manner in which Contingencies are identified for use in the TTC process.
- **R1.5.** The following information on how source and sink for transmission service is accounted for in ATC calculations including:
  - **R1.5.1.** Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point ~~O~~of Receipt (POR) field of the transmission reservation
  - **R1.5.2.** Define if the sink used for ATC calculations is obtained from the sink field or the Point ~~O~~of Delivery (POD) field of the transmission reservation
  - **R1.5.3.** The source/sink or POR/POD identification and mapping to the model.

**R1.5.4.** If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.

**R2.** When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R2.1.** Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.

**R2.2.** Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.

**R2.3.** Facility Ratings specified by the Generator Owners and Transmission Owners.

**R3.** When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):

**R3.1.1.** Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.

**R3.1.2.** Load forecast for the applicable period being calculated.

**R3.1.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R3.2.** For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):

**R3.2.1.** Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.

**R3.2.2.** Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.

**R3.2.3.** Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.

**R4.** When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R4.1.** Use all Contingencies meeting the criteria described in ~~its~~ the ATCID.

**R4.2.** Respect any contractual allocations of TTC.

**R4.3.** Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent

Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.

- If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

**R5.** Each Transmission Operator shall establish TTC for each ATC Path as defined below: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R5.1.** At least once within the seven calendar days ~~in the calendar week~~ prior to the specified period for TTCs used in hourly and daily ATC calculations.

**R5.2.** At least once per calendar month for TTCs used in monthly ATC calculations.

**R5.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.

**R6.** Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.1.** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:

- A System Operating Limit is reached on the Transmission Service Provider's system, or
- A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

**R6.2.** If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.

**R6.3.** Use (as the TTC) the lesser of:

– The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or

– The sum of Facility Ratings of all ties comprising the ATC Path.

**R6.4.** For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission ~~Operator~~ Service Provider so the TTC does not exceed ~~that Transmission Operator's~~ each Transmission Service Provider's contractual rights.

[1] The Transmission operator may honor distribution factors less than 5% if desired.

**R7.** The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.

**R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

**R8.** When calculating Existing Transmission Commitments (ETCs) for firm commitments ($ETC_F$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**$NITS_F$** is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_F$** is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or ~~"S~~safe ~~Harbor~~ harbor ~~Tariff~~tariff~~"~~ ~~accepted by FERC~~ on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_F$** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$ROR_F$** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**$OS_F$** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R9.** When calculating ETC for non-firm commitments ($ETC_{NF}$) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**$NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources)

reserved on ATC Paths that serve as interfaces with other Balancing Authorities.

**$GF_{NF}$** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or ~~"~~s~~S~~afe ~~Harbor~~ harbor ~~Tariff~~tariff~~"~~ ~~accepted by FERC~~ on ATC Paths that serve as interfaces with other Balancing Authorities.

**$PTP_{NF}$** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**$OS_{NF}$** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

**R10.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + counterflows_F$$

**Where:**

**$ATC_F$** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**$Postbacks_F$** are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_F$** are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

**R11.** When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

$$ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**$ATC_{NF}$** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**$ETC_F$** is the sum of existing firm Transmission commitments for the ATC Path during that period.

**$ETC_{NF}$** is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

**$CBM_S$** is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

**$TRM_U$** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**$Postbacks_{NF}$** are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$counterflows_{NF}$** are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

## C. Measures

**M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)

**M3.** Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)

**M4.** Each Transmission Operator shall provide the contingencies used in determining TTC and ~~its~~ the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)

**M5.** Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)

**M6.** Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)

**M7.** Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated

duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)

**M8.** Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)

**M9.** Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

**M10.** The ~~T~~Transmission Service Provider ~~must be capable of demonstrating~~shall demonstrate compliance with R8 by ~~that for any calculation of firm ETC made in the previous sixty days, the Transmission Service Provider can recalculate the individual value of the firm ETC for~~ recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate ~~this~~ the specified value for the designated ~~hour~~time period. The data used must meet the requirements specified in ~~the standard~~MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated ~~, and the audited~~ value ~~must~~ that is~~be~~ within +/- 15% or 15 MW, whichever is greater, of the ~~demonstrated result~~originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)

~~**M10.** (R8)~~

**M11.** The Transmission Service Provider ~~must be capable of demonstrating~~shall demonstrate compliance with R9 by ~~that for any calculation of non-firm ETC made in the previous sixty days, the Transmission Service Provider can~~ recalculat~~e~~ing ~~the individual value of the~~ non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate ~~this~~ the specified value for the designated ~~hour~~time period. The data used must meet the requirements specified in ~~the standard~~MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is ~~, and the audited value must be~~ within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC~~demonstrated result~~. (R9)

**M12.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)

**M13.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset

Not applicable.

#### 1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in ~~with~~ R8 and R9 for the most recent ~~sixty~~ 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Service Provider has an ATCID but it is missing one of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements)<br>~~The Transmission Service Provider has an ATCID that meets the intent of Requirement 1 but the ATCID is missing some minor information.~~ | The Transmission Service Provider has an ATCID but it is missing two of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements)<br>~~The Transmission Service Provider has an ATCID but it is missing one of the four required elements in R1.~~ | The Transmission Service Provider has an ATCID but it is missing three of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements)<br>~~The Transmission Service Provider has an ATCID but it is missing two of the four required elements in R1.~~ | The Transmission Service Provider has an ATCID but it is missing more than three of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ R1.3<br>▪ R1.4<br>▪ R1.5 (any one or more of its sub-subrequirements)<br>~~The Transmission Service Provider has an ATCID but it is missing three or more of the four required elements in R1.~~ |
| R2. | The Transmission Operator ~~utilized~~ used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>~~Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled~~used. | The Transmission Operator ~~utilized~~ used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>~~Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled~~used. | One or both of the following:<br>• The Transmission Operator ~~utilized~~ used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>~~OR~~<br>• The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) | One or more of the following:<br>• The Transmission Operator ~~utilized~~ used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.<br>~~OR~~<br>• The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability |

| R # | Lower VSL | Moderate ~~VSL~~ VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | for one adjacent Reliability Coordinator ~~area~~Area.<br><br>~~Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled~~used~~.~~ | Coordinator ~~area~~Area.<br><br>~~OR~~<br><br>• The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator ~~areas~~Areas.<br><br>~~Note: A modeling error (a violation of the criteria in R2) is a single violation, regardless how many times that error has been modeled~~used~~.~~ |
| R3. | The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID. | The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. | One or more ~~violations below constitutes a single violation of R3~~of the following:~~:~~<br><br>• The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.<br><br>~~OR~~<br><br>• The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3. |

| R # | Lower VSL | Moderate ~~VSL~~ | High VSL | Severe VSL |
|---|---|---|---|---|
| R4. | The Transmission ~~Service Provider~~Operator did not model reservations' sources or sinks as described in R5.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater~~,~~. | The Transmission ~~Service Provider~~Operator did not model reservations' sources or sinks as described in R5.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater~~,~~. | The Transmission ~~Service Provider~~Operator did not model reservations' sources or sinks as described in R5.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater~~,~~. | One or more of the following:<br>• The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID.<br>~~OR~~<br>• The Transmission Operator did not respect contractual allocations of TTC.<br>~~OR~~<br>• The Transmission ~~Service Provider~~Operator did not model reservations' sources or sinks as described in ~~R5~~R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater.<br>~~OR~~<br>• The Transmission Operator did not use firm reservations to estimate interchange or did not utilize that estimate in the TTC calculation as described in R4.3. |
| R5. | One or more of the following:<br>• The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days | One or more of the following:<br>• The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days | One or more of the following:<br>• The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days | One or more of the following:<br>• The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 16 calendar days<br>• The Transmission Operator did not establish TTCs for |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | • The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month<br>~~N/A~~ | • The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month ~~N/A~~ | • The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month<br>~~N/A~~ | use in monthly ATCs during a four or more consecutive calendar month period<br>• The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3<br>~~The Transmission Operator did not establish TTCs within the minimum time frames specified in R5.~~ |
| R6. | N/A | N/A | N/A | The Transmission Operator did not calculate TTCs per the process specified in R6. |
| R7. | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination.<br>~~OR~~<br>• The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination.<br>~~OR~~<br>• The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination.<br>~~OR~~<br>• The Transmission Operator has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been | One or more of the following:<br>• The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination.<br>~~OR~~<br>• The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations.<br>~~OR~~<br>• The Transmission Operator provided its Transmission Service Provider with its ATC |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | than 14 calendar days since their determination. | more than 21 calendar days after their determination. | more than 28 calendar days after their determination. | Path TTCs used in monthly ATC ~~calculations more~~calculations more than 28 calendar days after their determination. ~~OR~~ • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations. |
| R8. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in ~~M9~~ M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in ~~M9~~ M10 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in ~~M9~~ M10 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in ~~M9~~ M10 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R9. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in ~~M10~~ M11 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in ~~M10~~ M11 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in ~~M10~~ M11 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in ~~M10~~ M11 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | but not more than 35% of the value calculated in the measure or 35MW, whichever is greater... | but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | |
| R10. | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |
| R11. | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater). | The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater). |

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### Implementation Plan for Standard MOD-028-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-028-1 – Area Interchange Methodology, which describes the Area Interchange methodology (previously referred to as the Network Response ATC methodology) for determining ATC.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### Retired Standards

FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-028-1 incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

FAC-013-1 – Establish and Communicate Transfer Capabilities, includes two requirements. MOD-028-1 incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-028-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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# Implementation Plan for Standard MOD-028-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-028-1 – Area Interchange Methodology, which describes the Area Interchange methodology (previously referred to as the Network Response ATC methodology) for determining ATC.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Retired Standards

FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-028-1 incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

FAC-013-1 – Establish and Communicate Transfer Capabilities, includes two requirements. MOD-028-1 incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-028-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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# Summary of Process Steps Taken Following Posting of the Standards for 30-day Comment

The ATC Standard Drafting Team is developing the ATC-related standards, in part, as a response to FERC Order 890. Order 890 provided specific guidance on the timeliness of this standards development effort. The drafting team has been working to a strict time line to ensure it can file these standards in compliance with the Commission's directives, while also adhering to the NERC Reliability Standards Development Procedure.

As described in Step 8 of NERC's Reliability Standards Development Procedure,

> "Based on the comments received and field testing, the standard drafting team may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the effect or use of the standard."

When reviewing the comments received and considering changes to the standards, the drafting team also considered that any substantive changes to the requirements would require an additional 30-day comment and response period, which would eliminate the possibility of meeting the FERC's submission deadlines. The drafting team carefully weighed the reliability benefit of any changes to the standard, and attempted to limit its modifications to those that clarify or explain, rather than create new requirements or change intent. The changes to the standards made by the drafting team fall into one or more of the following categories:

- Corrections
- Redrafting of language that does not change intent
- Clarifications that better explain intent
- Modifications that change minor details, but not intent
- Modifications to ensure consistency and reduce ambiguity

The drafting team does not believe that any of the changes made to the requirements following the last comment period directly or materially affect the effect or use of the standards, but instead make the standards more clear.

The NERC Standards Committee is a stakeholder group responsible for the oversight of standards development, including evaluation of the responses to comments and any changes to the standards. As described in Step 8 of NERC's Reliability Standards Development Procedure:

> "When the Standards Committee receives a draft standard that is recommended for ballot, the Standards Committee will review the standard and recommendations of the standards process manager to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives and requirements cited in Steps 1 to 8, as applicable; has an implementation plan; and is compatible with other existing standards. If the proposed standard does not pass this review, the Standards Committee shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the Standards

> Committee shall set the proposed standard for ballot as soon as the work flow will accommodate."

NERC's Standards Process Manager presented the changes described above to the Executive Committee of the NERC Standards Committee on June 19, 2008. Following review of the revisions made to the standards, comment responses, and implementation plans, the Standards Committee's Executive Committee determined that the standards had passed the review, and the changes made do not directly or materially affect the effect or use of the standards. The Standards Committee's Executive Committee directed NERC's Standards Process Manager to post the standards for 30-day pre-ballot review and to begin assembling the ballot pools necessary for balloting.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.
7. SDT posted third draft for comment from April 16–May 15, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Respond to Comments. | June 20, 2008 |
| 2. Posting for 30-day Pre-Ballot Review. | June 20, 2008 |
| 3. Initial Ballot. | July 21, 2008 |
| 4. Respond to comments. | August 20, 2008 |
| 5. Recirculation ballot. | August 21, 2008 |
| 6. 30 Day posting before board adoption. | June 21, 2008 |
| 7. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Transmission Reliability Margin Implementation Document (TRMID):** A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**

2. **Number:** **MOD-008-1**

3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.

4. **Applicability:**

   **4.1.** Transmission Operators that maintain TRM.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value:

- Aggregate Load forecast.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions ).
- Reserve sharing requirements.
- Inertial response and frequency bias.

**R1.2.** The description of the method used to allocate TRM across ATC Paths or Flowgates.

**R1.3.** The identification of the TRM calculation used for the following time periods:

**R1.3.1.** Same day and real-time.

**R1.3.2.** Day-ahead and pre-schedule.

**R1.3.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

**R2.** Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.** Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

**R4.** Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

## C. Measures

**M1.** Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, or other evidence, (such as written documentation, study reports, documentation of its CBM process, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide evidence (such as copies of emails or postal receipts that show the recipient, date and contents) that the requested documentation (such as work papers and load flow cases) was made available within the specified timeframe to the requestor. (R3)

**M4.** Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

**M5.** Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.4. Compliance Monitoring and Enforcement Processes

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago. | The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.<br>**OR**<br>The Transmission Operator's TRMID does not address one of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3 | The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.<br>**OR**<br>The Transmission Operator's TRMID does not address two of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3 | The Transmission Operator has a TRMID that does not incorporate changes that have been made one year ago or more.<br>**OR**<br>The Transmission Operator does not have a TRMID.<br>**OR**<br>The Transmission Operator's TRMID does not address three of the following:<br>▪ R1.1<br>▪ R1.2<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3 |
| R2. | N/A | N/A | N/A | One or both of the following:<br>▪ The Transmission Operator included elements of uncertainty not defined in R1 in their establishment of TRM.<br>▪ The Transmission Operator included components of CBM in TRM. |
| R3. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days. | The Transmission Operator did not make the TRMID available for 90 days or more. |

| | | | | |
|---|---|---|---|---|
| R4 | The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (whichever is greater) were incorrect or missing. | The Transmission Operator did not establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). | The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago.<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values. | The Transmission Operator did not establish TRM<br>OR<br>The last determination of TRM was more than 18 months ago.<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing. |
| R5 | The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. Not more than 5% or 1 value (which ever is greater) were incorrect or missing. | The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 5% or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). | The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values. | The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or did not match those determined in R4. More than 15% or 3 values (which ever is greater) were incorrect or missing. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC authorized posting TTC/ATC/AFC SAR development June 20, 2005.
2. SAC authorized the SAR to be development as a standard on February 14, 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from May 25–June 25, 2007.
5. SDT posted second draft for comment from October 31–December 14, 2007.
6. SC conducted an Initial Ballot of the standard from March 3–12, 2008.
7. SDT posted third draft for comment from April 16–May 15, 2008.

**Description of Current Draft:**

This is the fourth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| **Anticipated Actions** | **Anticipated Date** |
|---|---|
| 1. Respond to Comments. | June 20, 2008 |
| 2. Posting for 30-day Pre-Ballot Review. | June 20, 2008 |
| 3. Initial Ballot. | July 21, 2008 |
| 4. Respond to comments. | August 20, 2008 |
| 5. Recirculation ballot. | August 21, 2008 |
| 6. 30 Day posting before board adoption. | June 21, 2008 |
| 7. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**Transmission Reliability Margin Implementation Document (TRMID):** A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.

## A. Introduction

1. **Title:** **Transmission Reliability Margin Calculation Methodology**
2. **Number:** **MOD-008-1**
3. **Purpose:** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.
4. **Applicability:**
   **4.1.** Transmission Operators that maintain TRM.
5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees.

## B. Requirements

**R1.** Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R1.1.** Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value:

- Aggregate Load forecast.
- Load distribution uncertainty.
- Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages).
- Allowances for parallel path (loop flow) impacts.
- Allowances for simultaneous path interactions.
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation).
- Short-term System Operator response (Operating Reserve actions ~~not exceeding a 59-minute window~~).
- Reserve sharing requirements.
- Inertial response and frequency bias.

**R1.2.** The description of the method used to allocate TRM across ATC Paths or Flowgates.

**R1.3.** The identification of the TRM calculation used for the following time periods:

**R1.3.1.** Same day and real-time.

**R1.3.2.** Day-ahead and pre-schedule.

**R1.3.3.** Beyond day-ahead and pre-schedule, up to thirteen months ahead.

**R2.** Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.** Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- Transmission Service Providers
- Reliability Coordinators
- Planning Coordinators
- Transmission Planner
- Transmission Operators

**R4.** Each Transmission Operator ~~using~~ that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R5.** The Transmission Operator ~~using~~ that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

## C. Measures

**M1.** Each Transmission Operator shall produce its TRMID evidencing inclusion of all specified information in R1. (R1)

**M2.** Each Transmission Operator shall provide evidence including its TRMID, TRM values, CBM values, ~~and CBMID ,~~ or other evidence, (such as written documentation, study reports, documentation of its CBM process, and supporting information) to demonstrate that its TRM values did not include any elements of uncertainty beyond those defined in R1.1 and to show that it did not include any of the components of CBM. (R2)

**M3.** Each Transmission Operator shall provide a dated copy of any request from an entity described in R3. The Transmission Operator shall also provide evidence (such as copies of emails or postal receipts that show the recipient, date and contents) that the requested documentation (such as work papers and load flow cases) was made available within the specified timeframe to the requestor. (R3)

**M4.** Each Transmission Operator shall provide evidence (such as logs, study report, review notes, or data) that it established TRM values at least once every thirteen months for each of the TRM time periods. (R4)

**M5.** Each Transmission Operator shall provide evidence (such as logs, email, website postings) that it provided their Transmission Service Provider(s) and Transmission Planner(s) with the updated TRM value as described in R5. (R5)

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Data Retention**

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1.
- The Transmission Operator shall retain evidence to show compliance with R2, R3, and R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall retain evidence to show compliance with R4 for the most recent three calendar years plus the current year.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes**

Any of the following may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | The Transmission Operator has a TRMID that does not incorporate changes made up to three months ago. | The Transmission Operator has a TRMID that does not incorporate changes that have been made three or more months ago but less than six months ago.<br>**OR**<br>The Transmission Operator's TRMID does not address one of the ~~sub requirements~~following:<br>▪ ~~(~~R1.1~~,~~<br>▪ R1.2~~,~~<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3~~).~~<br>~~Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3.~~ | The Transmission Operator has a TRMID that does not incorporate changes that have been made six or more months ago but less than one year ago.<br>**OR**<br>The Transmission Operator's TRMID does not address two of the ~~sub requirements (R1.1, R1.2, R1.3).~~ following:<br>▪ R1.1<br>▪ R1.2<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3<br>~~Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3.~~ | The Transmission Operator has a TRMID that does not incorporate changes that have been made one year ago or more.<br>**OR**<br>The Transmission Operator does not have a TRMID~~;~~.<br>**OR**<br>The Transmission Operator's TRMID does not address three of the ~~sub requirements (R1.1, R1.2, R1.3).~~following:<br>▪ R1.1<br>▪ R1.2<br>▪ Any one or more of the following:<br>o R1.3.1, R1.3.2 or R1.3.3~~Any violation or violations of the sub-requirements of R1.3 shall be considered a single violation of R1.3.~~ |
| R2. | N/A | N/A | N/A | One or both of the following:<br>▪ The Transmission Operator included elements of uncertainty not defined in R1 in their establishment of TRM. |

| | | | | |
|---|---|---|---|---|
| | | | | ~~OR~~<br>▪ The Transmission Operator included components of CBM in TRM. |
| R3. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in more than 30 days but less than 45 days. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 45 days or more but less than 60 days. | The Transmission Operator made the TRMID available to a requesting entity specified in R3 but provided TRMID in 60 days or more but less than 90 days. | The Transmission Operator did not make the TRMID available for 90 days or more. |
| R4 | The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. Not more than 5% or 1 value (which ever is greater) were incorrect or missing. | The Transmission Operator did not establish TRM within thirteen months of the previous determination, and the last determination was not more than 15 months ago<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete. More than 5%, or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). | The Transmission Operator did not establish TRM within 15 months of the previous determination, and the last determination was not more than 18 months ago.<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values. | The Transmission Operator did not establish TRM<br>OR<br>The last determination of TRM was more than 18 months ago.<br>OR<br>The Transmission Operator established TRM values on schedule BUT the values were incomplete or incorrect. More than 15% or 3 values (which ever is greater) were incorrect or missing. |
| R5 | The Transmission Operator did provide the TRM values to all entities specified in more then 7 days but less than 14 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or ~~incorrect~~did not match those determined in R4. | The Transmission Operator did provide the TRM values to all entities specified in 14 days or more, but less than 30 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or ~~incorrect~~did not match those determined in R4.~~.~~ | The Transmission Operator did provide the TRM values to all entities specified in 30 days or more, but less than 60 days.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or ~~incorrect~~did not match those determined in R4. | The Transmission Operator did not provide the TRM values to all entities specified within 60 days of the change.<br>OR<br>The Transmission Operator did provide TRM values on schedule BUT the values were incomplete or ~~incorrect~~ did not match those determined in R4. |

| | | | | |
|---|---|---|---|---|
| | Not more than 5% or 1 value (which ever is greater) were incorrect or missing. | More than 5%~~,~~ or 1 value (which ever is greater) were incorrect or missing, but not more than 10% or 2 values (whichever is greater). | More than 10% or 2 values (which ever is greater) were incorrect or missing, but not more than 15% or 3 values. | More than 15% or 3 values (which ever is greater) were incorrect or missing. |

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## Implementation Plan for Standard MOD-028-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-028-1 – Area Interchange Methodology, which describes the Area Interchange methodology (previously referred to as the Network Response ATC methodology) for determining ATC.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### Retired Standards

FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-028-1 incorporates the following requirements from FAC-012-1:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

FAC-013-1 – Establish and Communicate Transfer Capabilities, includes two requirements. MOD-028-1 incorporates the following requirements from FAC-013-1:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-028-1 becomes effective.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-028-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Implementation Plan for Standard MOD-008-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-008-1 – Transmission Reliability Margin which describes the reliability aspects of determining and maintaining a Transmission Reliability Margin and what components of uncertainty may be considered when making that determination.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Modified Standards

This standard supersedes MOD-008-0. MOD-009-0 – Procedure for Verifying Transmission Reliability Margin Values, has been incorporated into this standard, made irrelevant by this standard, or is being addressed by the North American Energy Standards Board, and should be retired when MOD-008-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-008-1 | ■ | | | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the Reliability Standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved by the NERC Board of Trustees. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Summary of Process Steps Taken Following Posting of the Standards for 30-day Comment

The ATC Standard Drafting Team is developing the ATC-related standards, in part, as a response to FERC Order 890. Order 890 provided specific guidance on the timeliness of this standards development effort. The drafting team has been working to a strict time line to ensure it can file these standards in compliance with the Commission's directives, while also adhering to the NERC Reliability Standards Development Procedure.

As described in Step 8 of NERC's Reliability Standards Development Procedure,

> "Based on the comments received and field testing, the standard drafting team may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the effect or use of the standard."

When reviewing the comments received and considering changes to the standards, the drafting team also considered that any substantive changes to the requirements would require an additional 30-day comment and response period, which would eliminate the possibility of meeting the FERC's submission deadlines. The drafting team carefully weighed the reliability benefit of any changes to the standard, and attempted to limit its modifications to those that clarify or explain, rather than create new requirements or change intent. The changes to the standards made by the drafting team fall into one or more of the following categories:

- Corrections
- Redrafting of language that does not change intent
- Clarifications that better explain intent
- Modifications that change minor details, but not intent
- Modifications to ensure consistency and reduce ambiguity

The drafting team does not believe that any of the changes made to the requirements following the last comment period directly or materially affect the effect or use of the standards, but instead make the standards more clear.

The NERC Standards Committee is a stakeholder group responsible for the oversight of standards development, including evaluation of the responses to comments and any changes to the standards. As described in Step 8 of NERC's Reliability Standards Development Procedure:

> "When the Standards Committee receives a draft standard that is recommended for ballot, the Standards Committee will review the standard and recommendations of the standards process manager to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives and requirements cited in Steps 1 to 8, as applicable; has an implementation plan; and is compatible with other existing standards. If the proposed standard does not pass this review, the Standards Committee shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the Standards

> Committee shall set the proposed standard for ballot as soon as the work flow will accommodate."

NERC's Standards Process Manager presented the changes described above to the Executive Committee of the NERC Standards Committee on June 19, 2008. Following review of the revisions made to the standards, comment responses, and implementation plans, the Standards Committee's Executive Committee determined that the standards had passed the review, and the changes made do not directly or materially affect the effect or use of the standards. The Standards Committee's Executive Committee directed NERC's Standards Process Manager to post the standards for 30-day pre-ballot review and to begin assembling the ballot pools necessary for balloting.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC Authorized posting TTC/ATC/AFC SAR Development June 20 2005.
2. SAC Authorized the SAR to be developed as a standard on February 14 2006.
3. SC appointed a Standard Drafting Team on March 17, 2006.
4. SDT posted first draft for comment from February 15–March 16, 2007.
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6. SDT posted third draft for comment from October 31–December 15, 2007.
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**Description of Current Draft:**

This is the fifth draft of the proposed standard posted for stakeholder comments. This draft includes consideration of stakeholder comments and applicable FERC directives from FERC Order 693, Order 890, and Order 890-A.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Respond to Comments. | June 20, 2008 |
| 2. Posting for 30-day Pre-Ballot Review. | June 20, 2008 |
| 3. Initial Ballot. | July 21, 2008 |
| 4. Respond to comments. | August 20, 2008 |
| 5. Recirculation ballot. | August 21, 2008 |
| 6. 30-day posting before board adoption. | June 21, 2008 |
| 7. Board adoption. | September 1, 2008 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**ATC Path:** Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[1].

**Available Transfer Capability (ATC):** A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.

**Available Transfer Capability Implementation Document (ATCID):** A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.

**Transmission Operator Area:** The collection of Transmission assets over which the Transmission Operator is responsible for operating.

**Existing Transmission Commitments (ETC):** Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

**Planning Coordinator:** See Planning Authority.

**Postback:** Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

**Business Practices:** Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices**.**

**Block Dispatch:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

**Dispatch Order:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

**Participation Factors:** A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.

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[1] See 18 CFR 37.6(b)(1)

## A. Introduction

1. **Title:** **Available Transmission System Capability**

2. **Number:** **MOD-001-1**

3. **Purpose:** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors

4. **Applicability:**

   **4.1.** Transmission Service Provider.

   **4.2.** Transmission Operator.

5. **Proposed Effective Date:** First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.

## B. Requirements

**R1.** Each Transmission Operator shall select one of the methodologies[2] listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- The Area Interchange Methodology, as described in MOD-028
- The Rated System Path Methodology, as described in MOD-029
- The Flowgate Methodology, as described in MOD-030

**R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Lower* [*Time Horizon: Operations Planning*]

**R2.1.** Hourly values for at least the next 48 hours.

**R2.2.** Daily values for at least the next 31 calendar days.

**R2.3.** Monthly values for at least the next 12 months (months 2-13).

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows including:

**R3.2.1.** How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

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[2] All ATC Paths do not have to use the same methodology and no particular ATC Path must use the same methodology for all time periods.

**R3.2.2.** A rationale for that accounting specified in R3.2.

**R3.3.** The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC or AFC.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.

**R3.5.** A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

**R3.6.** A description of how generation and transmission outages are considered in transfer or Flowgate capability calculations, including:

**R3.6.1.** The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.

**R3.6.2.** The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.

**R3.6.3.** How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.

**R4.** The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

**R4.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

**R4.3.** Each Transmission Operator associated with the Transmission Service Provider's area.

**R4.4.** Each Planning Coordinator adjacent to the Transmission Service Provider's area.

**R4.5.** Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

**R4.6.** Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

**R5.** The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.** When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.** When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.

**R8.2.** Daily values, once per day.

**R8.3.** Monthly values, once per week.

**R9.** Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor's ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations
- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.

> Note that the North American Energy Standards Board (NAESB) is developing the companion standards that address the posting of ATC information, including supporting information such as that described in R9.

- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

**R9.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

**R9.1.1.** If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available

**R9.1.2.** If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available

**R9.1.3.** If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available

**R9.2.** This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one of the specified methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator's operating area. (R1).

**M2.** The Transmission Service Provider shall provide ATC or AFC values and identification of the selected methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 48 hours of hourly values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily values calculated at all times. (R2.2)

- There has been at least the next 12 months of monthly values calculated at all times (Months 2-13). (R2.3)

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** The Transmission Service Provider shall provide evidence (such as dated electronic mail messages, mail receipts, or voice recordings) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

**M5.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

**M6.** The Transmission Operator shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate TTC or TFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC or TFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

**M7.** The Transmission Service Provider shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

**M8.** The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly values on at least the minimum frequencies specified in R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R8)

**M9.** The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R9. (R9)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

**1.3. Data Retention**

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Operator did not select one of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. |
| R2. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours.<br>▪ Has calculated daily ATC or AFC values for more than the next 21 calendar days but less than the next 31 calendar days.<br>▪ Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours.<br>▪ Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days.<br>▪ Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 21 hours.<br>▪ Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days.<br>▪ Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for less than the next 11 hours.<br>▪ Has calculated daily ATC or AFC values for less than the next 8 calendar days.<br>▪ Has calculated monthly ATC or AFC values for less than the next 4 months.<br>▪ Did not use the selected methodology(ies) to calculate ATC. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>**OR**<br>The Transmission Service Provider has an ATCID, but it does not include one or two of the information items described in R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>**OR**<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include three or more of the information items described in R3. |
| R4. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, but not more than 30 calendar days after, its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 90 calendar days after its implementation.<br>**OR**<br>The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation. |
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in R4. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R6. | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |
| R7 | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10%, of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |
| R8. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.<br>▪ For Daily, the values |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | ▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. | ▪ For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>▪ For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days. |
| R9 | N/A | The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available more than 30 calendar days but less than 45 calendar days after receiving a request. | The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available 45 calendar days or more but less than 60 calendar days after receiving a request. | The Transmission Service Provider did not make the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available for 60 calendar days or more after receiving a request. |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC Authorized posting TTC/ATC/AFC SAR Development June 20 2005.
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[1] See 18 CFR 37.6(b)(1)

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2. **Number:** **MOD-001-1**
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   - **4.2.** Transmission Operator.
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- The Flowgate Methodology, as described in MOD-030

**R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [*Violation Risk Factor: Lower* [*Time Horizon: Operations Planning*]

**R2.1.** Hourly values for at least the next 48 hours.

**R2.2.** Daily values for at least the next 31 calendar days.

**R2.3.** Monthly values for at least the next 12 months (months 2-13).

**R3.** Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R3.1.** Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.

**R3.2.** A description of the manner in which the Transmission Service Provider will account for counterflows including:

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[2] All ATC Paths do not have to use the same methodology and no particular ATC Path must use the same methodology for all time periods.

**R3.2.1.** How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm and non-firm ATC or AFC calculations.

**R3.2.2.** A rationale for th~~e defined~~ at accounting specified in R3.2. ~~.~~

**R3.3.** The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC ~~transfer of Flowgate capability~~or AFC.

**R3.4.** The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.

**R3.5.** A description of the allocation processes listed below that are applicable to the Transmission Service Provider:

- Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate.
- Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination.

**R3.6.** A description of how generation and transmission outages are considered in ~~ATC~~ transfer or Flowgate capability calculations, including:

**R3.6.1.** The criteria used to determine when an outage that is in effect part of a day impacts a daily ~~ATC or AFC~~ calculation.

**R3.6.2.** The criteria used to determine when an outage that is in effect part of a month impacts a monthly ~~ATC or AFC~~ calculation.

**R3.6.3.** How outages from other Transmission Service Providers ~~(including those outages from other Transmission Service Providers that are unrecognized)~~that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are ~~processed~~addressed~~,~~.

**R4.** The Transmission Service Provider shall notify the following entities ~~(via electronic mail)~~ before implementing a new or revised ATCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

**R4.1.** Each Planning Coordinator associated with the Transmission Service Provider's area.

**R4.2.** Each Reliability Coordinator associated with the Transmission Service Provider's area.

**R4.3.** Each Transmission Operator associated with the Transmission Service Provider's area.

**R4.4.** Each Planning Coordinator adjacent to the Transmission Service Provider's area.

**R4.5.** Each Reliability Coordinator adjacent to the Transmission Service Provider's area.

**R4.6.** Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.

**R5.** The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R6.** When calculating Total ~~t~~Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R7.** When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

**R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to ~~80~~ 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.

**R8.2.** Daily values, once per day.

**R8.3.** Monthly values, once per week.

**R9.** Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor's ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Expected generation and Transmission outages, additions, and retirements.
- Load forecasts.
- Unit commitments and order of dispatch, to include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:
  - Dispatch Order
  - Participation Factors
  - Block Dispatch
- Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service).
- Firm and non-firm Transmission reservations.
- Aggregated capacity set-aside for Grandfathered obligations

Note that the North American Energy Standards Board (NAESB) is developing the companion standards that address the posting of ATC information, including supporting information such as that described in R9.

- Firm roll-over rights.
- Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts.
- Power flow models and underlying assumptions.
- Contingencies, provided in one or more of the following formats:
  - A list of Elements
  - A list of Flowgates
  - A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider
- Facility Ratings.
- Any other services that impact Existing Transmission Commitments (ETCs).
- Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM)~~, and TTC~~ for all ATC Paths or Flowgates.
- Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service Provider receiving the request when selling Transmission service.
- Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service.
- Source and sink identification and mapping to the model.

**R9.1.** The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).

**R9.1.1.** If the Transmission Service Provider uses the data requested in its transfer or Flowgate capability calculations, it shall make the data used available

**R9.1.2.** If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available

**R9.1.3.** If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available

**R9.2.** This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requester and the provider).

## C. Measures

**M1.** The Transmission Operator shall provide evidence (such as a calculation, inclusion of the information in the ATCID, or other written documentation) that it has selected one of the specified methodologies per time period in R2 for use in determining Transfer Capabilities of those Facilities for each ATC Path within the Transmission Operator's operating area. (R1).

**M2.** The Transmission Service Provider shall provide ATC or AFC values and identification of the selected methodologies along with other evidence (such as written documentation, processes, or data) to show it calculated ATC or AFC for the following using the selected methodology or methodologies chosen as part of R1 (R2):

- There has been at least 48 hours of hourly values calculated at all times. (R2.1)
- There has been at least 31 consecutive calendar days of daily values calculated at all times. (R2.2)
- There has been at least the next 12 months of monthly values calculated at all times (Months 2-13). (R2.3)

**M3.** The Transmission Service Provider shall provide its current ATCID that contains all the information specified in R3. (R3)

**M4.** The Transmission Service Provider shall provide evidence (such as dated electronic mail messages, mail receipts, or voice recordings) that it has notified the entities specified in R4 before a new or revised ATCID was implemented. (R4)

**M5.** The Transmission Service Provider shall provide evidence (such as a demonstration) that the current ATCID is available to all of the entities specified in R4, as required by R5. (R5)

**M6.** The Transmission Operator shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides~~, load shedding~~ or data sources for load forecast and facility outages) used to calculate TTC or TFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining TTC or TFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Operator may demonstrate that the same load flow cases are used for both TTC or TFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R6)

**M7.** The Transmission Service Provider shall provide a copy of the assumptions (such as contingencies, loop flow, generation re-dispatch, switching operating guides~~, load shedding~~ or data sources for load forecast and facility outages) used to calculate ATC or AFC as well as other evidence (such as copies of operations planning studies, models, supporting information, or data) to show that the assumptions used in determining ATC or AFC are no more limiting than those used in planning of operations for the corresponding time period studied. Alternatively the Transmission Service Provider may demonstrate that the same load flow cases are used for both AFC and Operations Planning. When different inputs to the calculations are used because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall not be considered to be a difference in assumptions. (R7)

**M8.** The Transmission Service Provider calculating ATC shall provide evidence (such as logs or data) that it has calculated the hourly, daily, and monthly values on at least the minimum frequencies specified in R8 or provide evidence (such as data, procedures, or software documentation) that the calculated values identified in the ATC equation have not changed. (R8)

**M9.** The Transmission Service Provider shall provide a copy of the dated request, if any, for ATC or AFC data as well as evidence to show it responded to that request (such as logs or data) within thirty calendar days of receiving the request, and the requested data items were made available in accordance with R9. (R9)

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Data Retention**

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period to show compliance with R1.
- The Transmission Service Provider shall maintain evidence to show compliance with R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year.
- The Transmission Service Provider shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R3.
- The Transmission Service Provider shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year.
- The Transmission Operator shall maintain evidence to show compliance with R6 for the most recent calendar year plus the current year.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

-The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1. | N/A | N/A | N/A | The Transmission Operator did not select one of the specified methodologies for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. |
| R2. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 30 hours but less than the next 48 hours.<br>~~OR~~<br>▪ Has calculated daily ATC or AFC values for more than the next 21 calendar days but less than the next 31 calendar days.<br>~~OR~~<br>▪ Has calculated monthly ATC or AFC values for more than the next 9 months but less than the next 12 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 20 hours but less than the next 31 hours.<br>~~OR~~<br>▪ Has calculated daily ATC or AFC values for more than the next 14 calendar days but less than the next 22 calendar days.<br>~~OR~~<br>▪ Has calculated monthly ATC or AFC values for more than the next 6 months but less than the next 10 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated hourly ATC or AFC values for more than the next 10 hours but less than the next 21 hours.<br>~~OR~~<br>▪ Has calculated daily ATC or AFC values for more than the next 7 calendar days but less than the next 15 calendar days.<br>~~OR~~<br>▪ Has calculated monthly ATC or AFC values for more than the next 3 months but less than the next 7 months. | One or more of the following:<br>▪ The Transmission Service Provider has calculated ~~less than 11~~ hourly ATC or AFC values for less than the next 11 hours.<br>~~OR~~<br>▪ Has c~~C~~alculated ~~less than 8~~ daily ATC or AFC values for less than the next 8 calendar days.<br>~~OR~~<br>▪ Has c~~C~~alculated ~~less than4~~ monthly ATC or AFC values for less than the next 4 months.<br>~~OR~~<br>▪ Did not use the selected methodology(ies) to calculate ATC. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made up to three months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than three months but not more than six months ago. | The Transmission Service Provider has an ATCID that does not incorporate changes made more than six months but not more than one year ago.<br>**OR**<br>The Transmission Service Provider has an ATCID, but it does not include one or two ~~or more~~ of the information items described in R3. | The Transmission Service Provider has an ATCID that does not incorporate changes made a year or more ago.<br>**OR**<br>The Transmission Service Provider does not have an ATCID, or its ATCID does not include ~~any~~ three or more of the information items described in R3. |
| R4. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID after, but not more than 30 calendar days after, its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 30, but not more than 60, calendar days after its implementation. | The Transmission Service Provider notified one or more of the parties specified in R4 of a new or modified ATCID more than 60, but not more than 90, calendar days after its implementation. | The Transmission Service Provider ~~did not notify~~notified one or more of the parties specified in R4 of a new or modified ATCID ~~for~~ more than 90 calendar days after its implementation.<br>**OR**<br>The Transmission Service Provider did not notify one or more of the parties specified in R4 of a new or modified ATCID for more than 90 calendar days after its implementation. |
| R5. | N/A | N/A | N/A | The Transmission Service Provider did not make the ATCID available to the parties described in R4. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R6. | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10% of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | The Transmission Operator determined TTC or TFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |
| R7 | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than zero ATC Paths or Flowgates, but not more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 5% of all ATC Paths or Flowgates or 1 ATC Path or Flowgate (whichever is greater), but not more than 10% of all ATC Paths or Flowgates or 2 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 10%, of all ATC Paths or Flowgates or 2 ATC Path or Flowgate (whichever is greater), but not more than 15% of all ATC Paths or Flowgates or 3 ATC Paths or Flowgates (whichever is greater). | The Transmission Service Provider determined ATC or AFC using assumptions more limiting than those used in planning of operations for the studied time period for more than 15% of all ATC Paths or Flowgates or more than 3 ATC Paths or Flowgates (whichever is greater). |
| R8. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the ~~80~~175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the ~~80~~175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the ~~80~~175-hour per year requirement. | One or more of the following:<br>▪ For Hourly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the ~~80~~175-hour per year requirement. |

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | ~~OR~~<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.<br>~~OR~~<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. | ~~OR~~<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.<br>~~OR~~<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. | ~~OR~~<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.<br>~~OR~~<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. | ~~OR~~<br>For Daily, the values described in the ATC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.<br>~~OR~~<br>For Monthly, the values described in the ATC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days. |
| R9 | N/A | The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available more than 30 calendar days but less than 45 calendar days after receiving a request. | The Transmission Service Provider made the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available 45 calendar days or more but less than 60 calendar days after receiving a request. | The Transmission Service Provider did not make the requested data items specified in R9 available to the requesting entities specified within the requirement, per the schedule specified in the request, subject to the limitations specified in R9, available for 60 calendar days or more after receiving a request. |

# Implementation Plan for Standard MOD-001-1 (Project 2006-07)

## Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-001-1 – Available Transfer Capability which requires the selection of an ATC methodology and describes the parts of the ATC process that apply to all entities, regardless of methodology chosen.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

## Retired Standards

This standard supersedes the current MOD-001-0.

FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-001-1 incorporates the requirements from FAC-012-1 as follows:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

FAC-013-1 – Establish and Communicate Transfer Capabilities, includes two requirements. MOD-001-1 incorporates the two requirements from FAC-013-1 as follows:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

## Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-001-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

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## Implementation Plan for Standard MOD-001-1 (Project 2006-07)

### Summary

As part of compliance with FERC Order 890, the NERC ATC, TTC, CBM, & TRM Standards Drafting Team has prepared the following standard:

- MOD-001-1 – Available Transfer Capability which requires the selection of an ATC methodology and describes the parts of the ATC process that apply to all entities, regardless of methodology chosen.

### Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved, that must be implemented before this standard can be implemented.

### Retired Standards

This standard supersedes the current MOD-001-0.

FAC-012-1 – Transfer Capability Methodology includes four requirements. MOD-001-1 incorporates the requirements from FAC-012-1 as follows:

- R1 (Documentation of the Transfer Capability Methodology)
- R2, R3 (Communication of the Transfer Capability Methodology to appropriate entities).
- R4 (responding to comments by interested parties regarding the Transfer Capability Methodology) is being addressed by the North American Energy Standards Board.

As such, FAC-012-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

FAC-013-1 – Establish and Communicate Transfer Capabilities, includes two requirements. MOD-001-1 incorporates the two requirements from FAC-013-1 as follows:

- R1 (Calculation of the Transfer Capabilities)
- R2 (Communication of the Transfer Capabilities to appropriate entities).

As such, FAC-013-1 is no longer needed and is being retired when MOD-001-1 becomes effective.

### Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

| Proposed Standard | Transmission Operator | Transmission Planner | Transmission Service Provider | Balancing Authorities | Purchasing Selling Entities | Load-Serving Entities |
|---|---|---|---|---|---|---|
| MOD-001-1 | ■ | | ■ | | | |

## Proposed Effective Date

All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities. This 12-month time period is to allow entities to implement the standard (including the procurement of any new hardware or software required) and to test those implementations thoroughly.

# Summary of Process Steps Taken Following Posting of the Standards for 30-day Comment

The ATC Standard Drafting Team is developing the ATC-related standards, in part, as a response to FERC Order 890. Order 890 provided specific guidance on the timeliness of this standards development effort. The drafting team has been working to a strict time line to ensure it can file these standards in compliance with the Commission's directives, while also adhering to the NERC Reliability Standards Development Procedure.

As described in Step 8 of NERC's Reliability Standards Development Procedure,

> "Based on the comments received and field testing, the standard drafting team may include revisions that are not substantive. Substantive changes to a draft standard shall not be permitted between the last posting for stakeholder comment and submittal for ballot. A substantive change is one that directly and materially affects the effect or use of the standard."

When reviewing the comments received and considering changes to the standards, the drafting team also considered that any substantive changes to the requirements would require an additional 30-day comment and response period, which would eliminate the possibility of meeting the FERC's submission deadlines. The drafting team carefully weighed the reliability benefit of any changes to the standard, and attempted to limit its modifications to those that clarify or explain, rather than create new requirements or change intent. The changes to the standards made by the drafting team fall into one or more of the following categories:

- Corrections
- Redrafting of language that does not change intent
- Clarifications that better explain intent
- Modifications that change minor details, but not intent
- Modifications to ensure consistency and reduce ambiguity

The drafting team does not believe that any of the changes made to the requirements following the last comment period directly or materially affect the effect or use of the standards, but instead make the standards more clear.

The NERC Standards Committee is a stakeholder group responsible for the oversight of standards development, including evaluation of the responses to comments and any changes to the standards. As described in Step 8 of NERC's Reliability Standards Development Procedure:

> "When the Standards Committee receives a draft standard that is recommended for ballot, the Standards Committee will review the standard and recommendations of the standards process manager to ensure that the proposed standard is consistent with the scope of the SAR; addresses all of the objectives and requirements cited in Steps 1 to 8, as applicable; has an implementation plan; and is compatible with other existing standards. If the proposed standard does not pass this review, the Standards Committee shall remand the proposed standard to the standard drafting team to address the deficiencies. If the proposed standard passes the review, the Standards

Committee shall set the proposed standard for ballot as soon as the work flow will accommodate."

NERC's Standards Process Manager presented the changes described above to the Executive Committee of the NERC Standards Committee on June 19, 2008. Following review of the revisions made to the standards, comment responses, and implementation plans, the Standards Committee's Executive Committee determined that the standards had passed the review, and the changes made do not directly or materially affect the effect or use of the standards. The Standards Committee's Executive Committee directed NERC's Standards Process Manager to post the standards for 30-day pre-ballot review and to begin assembling the ballot pools necessary for balloting.

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# Standards Announcement

## Eight Recirculation Ballot Windows Open August 12, 2008

**Now available at:** https://standards.nerc.net/CurrentBallots.aspx

### Recirculation Ballot Windows for IRO-008-1, IRO-009-1 and IRO-010-1 Open August 12, 2008

The recirculation ballots for the following Interconnection Reliability Operating Limit (IROL) standards and their associated implementation plan open at 8 a.m. (EDT) on Tuesday, August 12, 2008:

- IRO-008-1— Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-009-1— Reliability Coordinator Actions to Operate within IROLs
- IRO-010-1— Reliability Coordinator Data Specification and Collection

These standards require the Reliability Coordinator (RC) to take actions to keep the bulk electric system operating within IROLs.

The ballot for each standard includes the retirement or revision of associated requirements from some already approved standards as identified in the table below. The IROL implementation plan contains the justification for the recommended retirements and revisions.

Note that during the initial ballot window, balloters identified some typographical errors in IRO-004 and IRO-005 and these have been corrected. A redline version of IRO-004 and IRO-005 has been posted to identify, with yellow highlighting, the corrections made. The corrections include the following:

- IRO-004 – changed the reference from “R7” to “R1” for the identification of the first set of VSLs
- IRO-005 – corrected the measures to reference the new requirement numbers

| Three Ballots for IROL Standards | |
|---|---|
| Ballot for New Standard | Includes Modifications to Associated Approved Standards |
| IRO-008 — RC Operational Analyses and Real-time Assessments | IRO-004-1 — RC – Operations Planning<br>▪ Retire R1 and R2 |
| IRO-009 — RC Actions to Operate within IROLs | EOP-001-0 — Emergency Operations Planning<br>▪ Retire R2 |
| | IRO-004-1 — RC – Operations Planning<br>▪ Retire R3 and R6 |
| | IRO-005-2 — RC – Current Day Operations<br>▪ Retire R3, R5, R16, R17;<br>▪ Modify R9, R13 and R14 |

| | |
|---|---|
| IRO-010 — RC Data Specification and Collection | IRO-002-1 — RC – Facilities<br>▪ Retire R2 |
| | IRO-004-1 — RC – Operations Planning<br>▪ Retire R4, R5 |
| | IRO-005-2 — RC – Current Day Operations<br>▪ Retire R2 |
| | TOP-003-0 — Planned Outage Coordination<br>▪ Modify R1.2 |
| | TOP-005-1 — Operational Reliability Information<br>▪ Retire R1, R1.1 |
| | TOP-006-1 — Monitoring System Conditions<br>▪ Modify R4 |

The recirculation ballot for each of the above standards will **close** at 8 p.m. (EDT) on Thursday, **August 21, 2008**.

**Five Recirculation Ballot Windows for Project 2006-07 — ATC/TTC and CBM/TRM Open August 12, 2008**

The recirculation ballots for the following ATC-related standards and their associated implementation plans open at 8 a.m. (EDT) on Tuesday, August 12, 2008:

- MOD-001-1 — Available Transfer Capability
- MOD-008-1 — Transmission Reliability Margin
- MOD-028-1 — Area Interchange Methodology
- MOD-029-1 — Rated System Path Methodology
- MOD-030-1 — Flowgate Methodology

This set of standards requires consistency in the calculation and documentation of Transmission Reliability Margin (TRM), Total Transfer Capability (TTC), Available Flowgate Capability (AFC), and Available Transfer Capability (ATC). (Note that the ATC-related standard for Capacity Benefit Margin is not included in this set of ballots).

The ballot for each standard includes the retirement of associated approved standards as identified in the table below. The implementation plans contain the justification for the recommended retirements.

Note that during the initial ballot window, balloters identified some typographical errors in MOD-030 and these have been corrected. The errors include the following:

- Applicability 4.1.1 - added a space between "(AFCs)" and "on"
- R1 - replaced the “period” with a “colon” following "(ATCID)"
- R2.1.2 - changed "analyses" to “analysis”
- Added "R"s to all "fourth-tier" requirements (e.g., changed “2.1.1.1” to “R2.1.1.1”)

A redline version of MOD-030 has been posted to identify, with yellow highlighting, the corrections made. In addition, all of the ATC-related standards were missing the “Regional Variances” and “Version History” sections of the standard and these have been added to all five of the standards.

During the initial ballot window, several balloters provided suggestions for additional improvements to MOD-030-1. (The suggested improvements are aimed at allowing additional methods of achieving the same reliability objective – the suggested improvements are not aimed at correcting any errors in MOD-030-1.) Under the existing standards development process, if the drafting team makes these changes to MOD-030-1, then the standard must be posted for an additional comment period, and then the balloting must begin again. This delay would mean that the standard would not be ready to file with FERC before its due date.

To remedy this problem, the drafting team has submitted a SAR to initiate modifications to MOD-030-1, and has received Standards Committee authorization to post the SAR and a proposed version of MOD-030-2 that reflects consideration of comments submitted with the initial ballot of MOD-030-1. The SAR and proposed MOD-030-2 are currently posted for stakeholder review and comment. As envisioned, MOD-030-2 will move through the standards development process and will be filed with governmental authorities before MOD-030-1 becomes effective.

| Five Ballots for ATC-related Standards | |
|---|---|
| Ballot for New Standard | Includes Retirement of Associated Approved Standards |
| MOD-001-1 — Available Transfer Capability | MOD-001-0 — Documentation of TTC and ATC Calculation Methodologies<br>FAC-012-1 — TC Methodology<br>FAC-013-1 — Establish and Communicate TCs |
| MOD-008-1 — Transmission Reliability Margin | MOD-008-0 — Documentation and Content of Each Regional TRM Methodology<br>MOD-009-0 — Procedure for Verifying TRM Values |
| MOD-028-1 — Area Interchange Methodology | FAC-012-1 — TC Methodology<br>FAC-013-1 — Establish and Communicate TCs |
| MOD-029-1 — Rated System Path Methodology | FAC-012-1 — TC Methodology<br>FAC-013-1 — Establish and Communicate TCs |
| MOD-030-1 — Flowgate Methodology | FAC-012-1 — TC Methodology<br>FAC-013-1 — Establish and Communicate TCs |

The recirculation ballot for each of the above standards will **close** at 8 p.m. (EDT) on Thursday, **August 21, 2008**.

*For more information or assistance, please contact Maureen Long,*
*Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.*

| Ballot Results | |
|---|---|
| Ballot Name: | ATC et al Standard - MOD-030_rc |
| Ballot Period: | 8/12/2008 - 8/21/2008 |
| Ballot Type: | recirculation |
| Total # Votes: | 220 |
| Total Ballot Pool: | 231 |
| Quorum: | 95.24 % The Quorum has been reached |
| Weighted Segment Vote: | 74.26 % |
| Ballot Results: | The Standard has Passed |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 64 | 1 | 30 | 0.652 | 16 | 0.348 | 13 | 5 |
| 2 - Segment 2. | 9 | 0.5 | 5 | 0.5 | 0 | 0 | 4 | 0 |
| 3 - Segment 3. | 65 | 1 | 41 | 0.732 | 15 | 0.268 | 7 | 2 |
| 4 - Segment 4. | 14 | 1 | 7 | 0.583 | 5 | 0.417 | 2 | 0 |
| 5 - Segment 5. | 36 | 1 | 23 | 0.767 | 7 | 0.233 | 5 | 1 |
| 6 - Segment 6. | 27 | 1 | 14 | 0.667 | 7 | 0.333 | 4 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 3 | 0.2 | 2 | 0.2 | 0 | 0 | 1 | 0 |
| 9 - Segment 9. | 5 | 0.4 | 4 | 0.4 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.5 | 4 | 0.4 | 1 | 0.1 | 2 | 0 |
| **Totals** | **231** | **6.6** | **130** | **4.901** | **51** | **1.699** | **39** | **11** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Ameren Services Company | Kirit S. Shah | Negative | View |
| 1 | American Electric Power | Paul B. Johnson | Affirmative | |
| 1 | American Transmission Company, LLC | Jason Shaver | Negative | View |
| 1 | Arizona Public Service Co. | Cary B. Deise | Affirmative | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | View |
| 1 | Basin Electric Power Cooperative | David Rudolph | Negative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | View |
| 1 | Brazos Electric Power Cooperative, Inc. | Tony Kroskey | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Abstain | |
| 1 | Central Lincoln PUD | Ronald Beck | Affirmative | View |
| 1 | Central Maine Power Company | Brian Conroy | | |
| 1 | City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power | Alan L Cooke | Affirmative | |
| 1 | City of Tallahassee | Gary S. Brinkworth | Abstain | |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | E.ON U.S. LLC | Larry Monday | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |

| | | | | |
|---|---|---|---|---|
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Affirmative | |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Manitoba Hydro | Michelle Rheault | Negative | View |
| 1 | Minnesota Power, Inc. | Carol Gerou | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Abstain | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Negative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Abstain | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Affirmative | |
| 1 | PacifiCorp | Robert Williams | Negative | View |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Portland General Electric Co. | Frank F. Afranji | Negative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Negative | View |
| 1 | Progress Energy Carolinas | Sammy Roberts | Affirmative | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Abstain | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Abstain | |
| 1 | Seattle City Light | Christopher M. Turner | Abstain | View |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Abstain | |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Abstain | View |
| 1 | Transmission Agency of Northern California | James W Beck | Abstain | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Abstain | |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Western Farmers Electric Coop. | Alan Derichsweiler | | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Abstain | |
| 2 | British Columbia Transmission Corporation | Phil Park | Abstain | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | View |
| 2 | New Brunswick System Operator | Alden Briggs | Affirmative | |
| 2 | New York Independent System Operator | Gregory Campoli | Abstain | |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Ameren Services Company | Mark Peters | Negative | View |
| 3 | American Electric Power | Raj Rana | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Negative | View |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Blachly-Lane Electric Co-op | Bud Tracy | Affirmative | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | View |
| 3 | City of McMinnville | Rick Rozanski | Affirmative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Negative | View |
| 3 | Clatskanie People's Utility District | Joseph Taffe | Negative | View |
| 3 | Clearwater Power Co. | Dave Hagen | Affirmative | View |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Constellation Energy | Carolyn Ingersoll | Affirmative | |
| 3 | Consumers Energy | David A. Lapinski | Abstain | |

| | | | | |
|---|---|---|---|---|
| 3 | Coos-Curry Electric Cooperative, Inc | Roger Meader | Affirmative | View |
| 3 | Cowlitz County PUD | Russell A Noble | Affirmative | View |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | View |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Grays Harbor PUD | Wesley W Gray | Negative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Affirmative | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | |
| 3 | Lost River Electric Cooperative | Richard Reynolds | Affirmative | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Negative | View |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | Nevada Power Co. | Sheryl Torrey | Negative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Niagara Mohawk (National Grid Company) | Michael Schiavone | Affirmative | |
| 3 | Northern Indiana Public Service Co. | William SeDoris | Negative | |
| 3 | Northern Lights Inc. | Jon Shelby | Affirmative | |
| 3 | Northern Wasco County People's Utility District (PUD) | Paul Titus | Affirmative | View |
| 3 | Okanogan County Electric Cooperative, Inc. | Ray Ellis | Affirmative | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Abstain | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Abstain | |
| 3 | Progress Energy Carolinas | Sam Waters | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Abstain | |
| 3 | Public Utility District No. 1 of Benton County | Gloria Bender | Affirmative | View |
| 3 | Public Utility District No. 1 of Franklin County | Linda Boomer | Affirmative | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Negative | View |
| 3 | Raft River Rural Electric Cooperative | Heber Carpenter | Affirmative | View |
| 3 | Salmon River Electric Cooperative | Ken Dizes | Affirmative | |
| 3 | Salt River Project | John T. Underhill | Affirmative | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | | |
| 3 | Umatilla Electric Cooperative | Steve Eldrige | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | Alliant Energy Corp. Services, Inc. | Kenneth Goldsmith | Negative | View |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Eugene Water & Electric Board | Dean Ahlsten | Affirmative | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Affirmative | |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Negative | View |
| 4 | Northern California Power Agency | Fred E. Young | Abstain | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Negative | |
| 4 | Pacific Northwest Generating Cooperative | Aleka K Scott | Affirmative | |
| 4 | Public Power Council | Nancy Baker | Affirmative | View |
| 4 | Public Utility District No. 1 of Douglas County | Henry E. LuBean | Negative | View |
| 4 | Public Utility District No. 1 of Snohomish County | John D. Martinsen | Affirmative | View |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 5 | AEP Service Corp. | Brock Ondayko | Affirmative | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | View |

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|---|---|---|---|---|
| 5 | City of Farmington | Clinton J Jacobs | Affirmative | |
| 5 | City of Tallahassee | Alan Gale | Affirmative | |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Deseret Power | Philip B Tice Jr | Affirmative | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Affirmative | |
| 5 | Entergy Corporation | Stanley M Jaskot | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | IBERDROLA RENEWABLES | Laura Beane | Negative | View |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Negative | View |
| 5 | New York Power Authority | Gerald Mannarino | Affirmative | |
| 5 | Orlando Utilities Commission | Richard Kinas | Abstain | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Negative | View |
| 5 | Progress Energy Carolinas | Wayne Lewis | Affirmative | |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seattle City Light | Michael J. Haynes | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | | |
| 5 | Southeastern Power Administration | Douglas Spencer | Affirmative | |
| 5 | Southern California Edison Co. | David Schiada | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Abstain | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | U.S. Bureau of Reclamation | Martin Bauer | Abstain | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Affirmative | |
| 6 | AEP Marketing | Edward P. Cox | Affirmative | |
| 6 | Barry Green Consulting Inc. | Barry Green | Affirmative | |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | View |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | IBERDROLA RENEWABLES | Kellie J Schreiner | Negative | View |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Negative | View |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | Portland General Electric Co. | John Jamieson | Negative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Negative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Affirmative | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Abstain | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | Southern California Edison Co. | Marcus V Lotto | Abstain | |
| 6 | Tampa Electric Co. | Jose Benjamin Quintas | | |
| 6 | Tenaska Power Services Co. | Cliff T Richardson | Abstain | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Affirmative | |
| 7 | Eastman Chemical Company | Lloyd Webb | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Abstain | |
| 8 | Other | Michehl R. Gent | Affirmative | |
| 8 | Volkmann Consulting | Terry Volkmann | Affirmative | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| | National Association of Regulatory Utility | | | |

| | | | | |
|---|---|---|---|---|
| 9 | Commissioners | Diane J. Barney | | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Abstain | View |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | SERC Reliability Corporation | Carter B Edge | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Abstain | |
| | | | | |

Legal and Privacy : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
*Washington Office:* 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC et al Standard - MOD-029_rc |
| **Ballot Period:** | 8/12/2008 - 8/21/2008 |
| **Ballot Type:** | recirculation |
| **Total # Votes:** | 215 |
| **Total Ballot Pool:** | 225 |
| **Quorum:** | **95.56 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 92.24 % |
| **Ballot Results:** | **The Standard has Passed** |

**Summary of Ballot Results**

| Segment | Ballot Pool | Segment Weight | Affirmative | | Negative | | Abstain | No Vote |
|---|---|---|---|---|---|---|---|---|
| | | | # Votes | Fraction | # Votes | Fraction | # Votes | |
| 1 - Segment 1. | 63 | 1 | 37 | 0.902 | 4 | 0.098 | 18 | 4 |
| 2 - Segment 2. | 9 | 0.6 | 6 | 0.6 | 0 | 0 | 3 | 0 |
| 3 - Segment 3. | 63 | 1 | 44 | 0.936 | 3 | 0.064 | 14 | 2 |
| 4 - Segment 4. | 13 | 0.9 | 6 | 0.6 | 3 | 0.3 | 4 | 0 |
| 5 - Segment 5. | 35 | 1 | 22 | 0.957 | 1 | 0.043 | 11 | 1 |
| 6 - Segment 6. | 26 | 1 | 16 | 1 | 0 | 0 | 8 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 3 | 0.2 | 2 | 0.2 | 0 | 0 | 1 | 0 |
| 9 - Segment 9. | 5 | 0.4 | 4 | 0.4 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.4 | 4 | 0.4 | 0 | 0 | 3 | 0 |
| **Totals** | **225** | **6.5** | **141** | **5.995** | **11** | **0.505** | **63** | **10** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Ameren Services Company | Kirit S. Shah | Abstain | |
| 1 | American Electric Power | Paul B. Johnson | Affirmative | |
| 1 | American Transmission Company, LLC | Jason Shaver | Abstain | |
| 1 | Arizona Public Service Co. | Cary B. Deise | Affirmative | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Basin Electric Power Cooperative | David Rudolph | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | |
| 1 | Brazos Electric Power Cooperative, Inc. | Tony Kroskey | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Abstain | |
| 1 | Central Lincoln PUD | Ronald Beck | Affirmative | |
| 1 | Central Maine Power Company | Brian Conroy | | |
| 1 | City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power | Alan L Cooke | Affirmative | |
| 1 | City of Tallahassee | Gary S. Brinkworth | Abstain | |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Affirmative | |
| 1 | Deseret Power | James Tucker | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | E.ON U.S. LLC | Larry Monday | Abstain | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Abstain | |

| | | | | |
|---|---|---|---|---|
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Great River Energy | Gordon Pietsch | Abstain | |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Affirmative | |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | |
| 1 | Lincoln Electric System | Doug Bantam | Abstain | |
| 1 | Minnesota Power, Inc. | Carol Gerou | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Abstain | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Abstain | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Abstain | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Affirmative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Progress Energy Carolinas | Sammy Roberts | Abstain | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Abstain | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Abstain | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | View |
| 1 | Transmission Agency of Northern California | James W Beck | Abstain | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Affirmative | |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Western Farmers Electric Coop. | Alan Derichsweiler | | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Abstain | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | |
| 2 | New Brunswick System Operator | Alden Briggs | Affirmative | |
| 2 | New York Independent System Operator | Gregory Campoli | Abstain | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Ameren Services Company | Mark Peters | Abstain | |
| 3 | American Electric Power | Raj Rana | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Affirmative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Blachly-Lane Electric Co-op | Bud Tracy | Affirmative | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | |
| 3 | City of McMinnville | Rick Rozanski | Affirmative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Negative | View |
| 3 | Clatskanie People's Utility District | Joseph Taffe | Negative | |
| 3 | Clearwater Power Co. | Dave Hagen | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Constellation Energy | Carolyn Ingersoll | Affirmative | |
| 3 | Consumers Energy | David A. Lapinski | Abstain | |
| 3 | Coos-Curry Electric Cooperative, Inc | Roger Meader | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | View |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Abstain | |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Grays Harbor PUD | Wesley W Gray | Abstain | |
| 3 | Great River Energy | Sam Kokkinen | Abstain | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Affirmative | |
| 3 | Lincoln Electric System | Bruce Merrill | Abstain | |
| 3 | Lost River Electric Cooperative | Richard Reynolds | Affirmative | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Abstain | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Abstain | |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | Nevada Power Co. | Sheryl Torrey | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Niagara Mohawk (National Grid Company) | Michael Schiavone | Affirmative | |
| 3 | Northern Indiana Public Service Co. | William SeDoris | Affirmative | |
| 3 | Northern Lights Inc. | Jon Shelby | Affirmative | |
| 3 | Northern Wasco County People's Utility District (PUD) | Paul Titus | Affirmative | |
| 3 | Okanogan County Electric Cooperative, Inc. | Ray Ellis | Affirmative | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Affirmative | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Abstain | |
| 3 | Progress Energy Carolinas | Sam Waters | Abstain | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Abstain | |
| 3 | Public Utility District No. 1 of Benton County | Gloria Bender | Affirmative | |
| 3 | Public Utility District No. 1 of Franklin County | Linda Boomer | Affirmative | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Affirmative | |
| 3 | Raft River Rural Electric Cooperative | Heber Carpenter | Affirmative | |
| 3 | Salmon River Electric Cooperative | Ken Dizes | Affirmative | |
| 3 | Salt River Project | John T. Underhill | Affirmative | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | | |
| 3 | Umatilla Electric Cooperative | Steve Eldrige | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Abstain | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | Alliant Energy Corp. Services, Inc. | Kenneth Goldsmith | Abstain | |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Affirmative | |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Abstain | |
| 4 | Northern California Power Agency | Fred E. Young | Abstain | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Negative | |
| 4 | Pacific Northwest Generating Cooperative | Aleka K Scott | Affirmative | |
| 4 | Public Power Council | Nancy Baker | Affirmative | |
| 4 | Public Utility District No. 1 of Douglas County | Henry E. LuBean | Negative | View |
| 4 | Public Utility District No. 1 of Snohomish County | John D. Martinsen | Affirmative | |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 5 | AEP Service Corp. | Brock Ondayko | Affirmative | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | |
| 5 | City of Farmington | Clinton J Jacobs | Affirmative | |
| 5 | City of Tallahassee | Alan Gale | Affirmative | |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Deseret Power | Philip B Tice Jr | Affirmative | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Affirmative | |
| 5 | Entergy Corporation | Stanley M Jaskot | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Abstain | |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Abstain | |
| 5 | IBERDROLA RENEWABLES | Laura Beane | Affirmative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Abstain | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Abstain | |
| 5 | New York Power Authority | Gerald Mannarino | Affirmative | |
| 5 | Orlando Utilities Commission | Richard Kinas | Abstain | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Abstain | |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seattle City Light | Michael J. Haynes | Abstain | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | | |
| 5 | Southeastern Power Administration | Douglas Spencer | Affirmative | |
| 5 | Southern California Edison Co. | David Schiada | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Abstain | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | U.S. Bureau of Reclamation | Martin Bauer | Abstain | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Affirmative | |
| 6 | AEP Marketing | Edward P. Cox | Affirmative | |
| 6 | Barry Green Consulting Inc. | Barry Green | Affirmative | |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Abstain | |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Abstain | |
| 6 | IBERDROLA RENEWABLES | Kellie J Schreiner | Affirmative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Abstain | |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Abstain | |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | Portland General Electric Co. | John Jamieson | Abstain | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Affirmative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Abstain | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | Southern California Edison Co. | Marcus V Lotto | Affirmative | |
| 6 | Tampa Electric Co. | Jose Benjamin Quintas | | |
| 6 | Tenaska Power Services Co. | Cliff T Richardson | Abstain | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Affirmative | |
| 7 | Eastman Chemical Company | Lloyd Webb | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Abstain | |
| 8 | Other | Michehl R. Gent | Affirmative | |
| 8 | Volkmann Consulting | Terry Volkmann | Affirmative | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Abstain | View |
| 10 | Midwest Reliability Organization | Larry Brusseau | Abstain | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | SERC Reliability Corporation | Carter B Edge | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Abstain | |
| | | | | |

Legal and Privacy : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
*Washington Office:* 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

| Ballot Results | |
|---|---|
| Ballot Name: | ATC et al Standard - MOD-028_rc |
| Ballot Period: | 8/12/2008 - 8/21/2008 |
| Ballot Type: | recirculation |
| Total # Votes: | 214 |
| Total Ballot Pool: | 224 |
| Quorum: | 95.54 % The Quorum has been reached |
| Weighted Segment Vote: | 79.34 % |
| Ballot Results: | The Standard has Passed |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 62 | 1 | 25 | 0.758 | 8 | 0.242 | 25 | 4 |
| 2 - Segment 2. | 9 | 0.5 | 5 | 0.5 | 0 | 0 | 4 | 0 |
| 3 - Segment 3. | 63 | 1 | 27 | 0.844 | 5 | 0.156 | 29 | 2 |
| 4 - Segment 4. | 13 | 0.7 | 2 | 0.2 | 5 | 0.5 | 6 | 0 |
| 5 - Segment 5. | 36 | 1 | 17 | 0.85 | 3 | 0.15 | 15 | 1 |
| 6 - Segment 6. | 25 | 1 | 11 | 0.846 | 2 | 0.154 | 10 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 3 | 0.2 | 2 | 0.2 | 0 | 0 | 1 | 0 |
| 9 - Segment 9. | 5 | 0.4 | 4 | 0.4 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.5 | 4 | 0.4 | 1 | 0.1 | 2 | 0 |
| **Totals** | **224** | **6.3** | **97** | **4.998** | **24** | **1.302** | **93** | **10** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Ameren Services Company | Kirit S. Shah | Abstain | |
| 1 | American Electric Power | Paul B. Johnson | Affirmative | |
| 1 | American Transmission Company, LLC | Jason Shaver | Abstain | |
| 1 | Arizona Public Service Co. | Cary B. Deise | Affirmative | |
| 1 | Avista Corp. | Scott Kinney | Abstain | |
| 1 | Basin Electric Power Cooperative | David Rudolph | Negative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Abstain | |
| 1 | Brazos Electric Power Cooperative, Inc. | Tony Kroskey | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Abstain | |
| 1 | Central Lincoln PUD | Ronald Beck | Abstain | |
| 1 | Central Maine Power Company | Brian Conroy | | |
| 1 | City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power | Alan L Cooke | Affirmative | |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | E.ON U.S. LLC | Larry Monday | Abstain | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Abstain | |
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |

| | | | | |
|---|---|---|---|---|
| 1 | Florida Power & Light Co. | C. Martin Mennes | Abstain | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Affirmative | |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Minnesota Power, Inc. | Carol Gerou | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Abstain | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Abstain | |
| 1 | PacifiCorp | Robert Williams | Abstain | |
| 1 | Platte River Power Authority | John C Collins | Abstain | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Progress Energy Carolinas | Sammy Roberts | Abstain | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Abstain | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Abstain | |
| 1 | Salt River Project | Robert Kondziolka | Abstain | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Abstain | |
| 1 | Seattle City Light | Christopher M. Turner | Abstain | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Abstain | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Abstain | View |
| 1 | Transmission Agency of Northern California | James W Beck | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Abstain | |
| 1 | Western Area Power Administration | Robert Temple | Abstain | |
| 1 | Western Farmers Electric Coop. | Alan Derichsweiler | | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Abstain | |
| 2 | California ISO | David Hawkins | Abstain | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | |
| 2 | New Brunswick System Operator | Alden Briggs | Affirmative | |
| 2 | New York Independent System Operator | Gregory Campoli | Abstain | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Ameren Services Company | Mark Peters | Abstain | |
| 3 | American Electric Power | Raj Rana | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Abstain | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Blachly-Lane Electric Co-op | Bud Tracy | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Abstain | |
| 3 | City of McMinnville | Rick Rozanski | Affirmative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Negative | View |
| 3 | Clatskanie People's Utility District | Joseph Taffe | Abstain | |
| 3 | Clearwater Power Co. | Dave Hagen | Abstain | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Constellation Energy | Carolyn Ingersoll | Affirmative | |
| 3 | Consumers Energy | David A. Lapinski | Abstain | |
| 3 | Coos-Curry Electric Cooperative, Inc | Roger Meader | Abstain | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | View |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Abstain | |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Grays Harbor PUD | Wesley W Gray | Abstain | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Affirmative | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Lost River Electric Cooperative | Richard Reynolds | Abstain | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Abstain | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Affirmative | |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | Nevada Power Co. | Sheryl Torrey | Abstain | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Niagara Mohawk (National Grid Company) | Michael Schiavone | Affirmative | |
| 3 | Northern Indiana Public Service Co. | William SeDoris | Affirmative | |
| 3 | Northern Lights Inc. | Jon Shelby | Abstain | |
| 3 | Northern Wasco County People's Utility District (PUD) | Paul Titus | Abstain | |
| 3 | Okanogan County Electric Cooperative, Inc. | Ray Ellis | Abstain | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Affirmative | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Abstain | |
| 3 | Progress Energy Carolinas | Sam Waters | Abstain | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Abstain | |
| 3 | Public Utility District No. 1 of Benton County | Gloria Bender | Abstain | |
| 3 | Public Utility District No. 1 of Franklin County | Linda Boomer | Abstain | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Abstain | |
| 3 | Raft River Rural Electric Cooperative | Heber Carpenter | Abstain | |
| 3 | Salmon River Electric Cooperative | Ken Dizes | Abstain | |
| 3 | Salt River Project | John T. Underhill | Abstain | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Abstain | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | | |
| 3 | Umatilla Electric Cooperative | Steve Eldrige | Abstain | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | Alliant Energy Corp. Services, Inc. | Kenneth Goldsmith | Negative | View |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Affirmative | |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Negative | View |
| 4 | Northern California Power Agency | Fred E. Young | Abstain | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Negative | |
| 4 | Pacific Northwest Generating Cooperative | Aleka K Scott | Abstain | |
| 4 | Public Power Council | Nancy Baker | Abstain | |
| 4 | Public Utility District No. 1 of Douglas County | Henry E. LuBean | Negative | View |
| 4 | Public Utility District No. 1 of Snohomish County | John D. Martinsen | Abstain | |
| 4 | Seattle City Light | Hao Li | Abstain | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 5 | AEP Service Corp. | Brock Ondayko | Affirmative | |
| 5 | Avista Corp. | Edward F. Groce | Abstain | |
| 5 | BC Hydro and Power Authority | Clement Ma | Abstain | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Abstain | |
| 5 | City of Farmington | Clinton J Jacobs | Affirmative | |
| 5 | City of Tallahassee | Alan Gale | Affirmative | |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 5 | Constellation Generation Group | Michael F. Gildea | Abstain | |
| 5 | Deseret Power | Philip B Tice Jr | Affirmative | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Affirmative | |
| 5 | Entergy Corporation | Stanley M Jaskot | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Abstain | |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | IBERDROLA RENEWABLES | Laura Beane | Abstain | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Abstain | |
| 5 | New York Power Authority | Gerald Mannarino | Affirmative | |
| 5 | Orlando Utilities Commission | Richard Kinas | Abstain | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Abstain | |
| 5 | Salt River Project | Glen Reeves | Abstain | |
| 5 | Seattle City Light | Michael J. Haynes | Abstain | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | | |
| 5 | Southeastern Power Administration | Douglas Spencer | Affirmative | |
| 5 | Southern California Edison Co. | David Schiada | Abstain | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Abstain | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | U.S. Bureau of Reclamation | Martin Bauer | Abstain | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Affirmative | |
| 6 | AEP Marketing | Edward P. Cox | Affirmative | |
| 6 | Barry Green Consulting Inc. | Barry Green | Affirmative | |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Abstain | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Abstain | |
| 6 | Dominion Resources, Inc. | Louis S Slade | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Abstain | |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | IBERDROLA RENEWABLES | Kellie J Schreiner | Abstain | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Abstain | |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Affirmative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Abstain | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Abstain | |
| 6 | Salt River Project | Mike Hummel | Abstain | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | Southern California Edison Co. | Marcus V Lotto | Abstain | |
| 6 | Tampa Electric Co. | Jose Benjamin Quintas | | |
| 6 | Tenaska Power Services Co. | Cliff T Richardson | Abstain | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Affirmative | |
| 7 | Eastman Chemical Company | Lloyd Webb | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Abstain | |
| 8 | Other | Michehl R. Gent | Affirmative | |
| 8 | Volkmann Consulting | Terry Volkmann | Affirmative | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Abstain | View |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 10 | SERC Reliability Corporation | Carter B Edge | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Abstain | |
| | | | | |

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*Washington Office:* 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC et al Standard - MOD-008_rc |
| **Ballot Period:** | 8/12/2008 - 8/21/2008 |
| **Ballot Type:** | recirculation |
| **Total # Votes:** | 216 |
| **Total Ballot Pool:** | 227 |
| **Quorum:** | **95.15 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 81.49 % |
| **Ballot Results:** | **The Standard has Passed** |

Summary of Ballot Results

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 64 | 1 | 43 | 0.811 | 10 | 0.189 | 6 | 5 |
| 2 - Segment 2. | 9 | 0.9 | 9 | 0.9 | 0 | 0 | 0 | 0 |
| 3 - Segment 3. | 63 | 1 | 49 | 0.891 | 6 | 0.109 | 6 | 2 |
| 4 - Segment 4. | 13 | 1 | 6 | 0.545 | 5 | 0.455 | 2 | 0 |
| 5 - Segment 5. | 36 | 1 | 26 | 0.813 | 6 | 0.188 | 3 | 1 |
| 6 - Segment 6. | 26 | 1 | 19 | 0.826 | 4 | 0.174 | 1 | 2 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 3 | 0.2 | 1 | 0.1 | 1 | 0.1 | 1 | 0 |
| 9 - Segment 9. | 5 | 0.4 | 4 | 0.4 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.6 | 5 | 0.5 | 1 | 0.1 | 1 | 0 |
| **Totals** | **227** | **7.1** | **162** | **5.786** | **33** | **1.315** | **21** | **11** |

Individual Ballot Pool Results

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Ameren Services Company | Kirit S. Shah | Negative | View |
| 1 | American Electric Power | Paul B. Johnson | Affirmative | View |
| 1 | American Transmission Company, LLC | Jason Shaver | Affirmative | |
| 1 | Arizona Public Service Co. | Cary B. Deise | Affirmative | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Basin Electric Power Cooperative | David Rudolph | Negative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | |
| 1 | Brazos Electric Power Cooperative, Inc. | Tony Kroskey | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Abstain | |
| 1 | Central Lincoln PUD | Ronald Beck | Affirmative | |
| 1 | Central Maine Power Company | Brian Conroy | | |
| 1 | City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power | Alan L Cooke | Affirmative | |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | E.ON U.S. LLC | Larry Monday | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |

| | | | | |
|---|---|---|---|---|
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Affirmative | |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | |
| 1 | Lincoln Electric System | Doug Bantam | Negative | |
| 1 | Manitoba Hydro | Michelle Rheault | Affirmative | |
| 1 | Minnesota Power, Inc. | Carol Gerou | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Affirmative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Abstain | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Abstain | |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Affirmative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Progress Energy Carolinas | Sammy Roberts | Affirmative | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Abstain | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Abstain | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Affirmative | View |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Western Farmers Electric Coop. | Alan Derichsweiler | | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Affirmative | |
| 2 | New Brunswick System Operator | Alden Briggs | Affirmative | |
| 2 | New York Independent System Operator | Gregory Campoli | Affirmative | |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Ameren Services Company | Mark Peters | Negative | View |
| 3 | American Electric Power | Raj Rana | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Affirmative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Blachly-Lane Electric Co-op | Bud Tracy | Affirmative | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | |
| 3 | City of McMinnville | Rick Rozanski | Abstain | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Negative | View |
| 3 | Clatskanie People's Utility District | Joseph Taffe | Affirmative | |
| 3 | Clearwater Power Co. | Dave Hagen | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Constellation Energy | Carolyn Ingersoll | Affirmative | View |
| 3 | Consumers Energy | David A. Lapinski | Abstain | |

| | | | | |
|---|---|---|---|---|
| 3 | Coos-Curry Electric Cooperative, Inc | Roger Meader | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Affirmative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Grays Harbor PUD | Wesley W Gray | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Affirmative | |
| 3 | Lincoln Electric System | Bruce Merrill | Negative | View |
| 3 | Lost River Electric Cooperative | Richard Reynolds | Affirmative | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Affirmative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Affirmative | |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | Nevada Power Co. | Sheryl Torrey | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Northern Indiana Public Service Co. | William SeDoris | Affirmative | |
| 3 | Northern Lights Inc. | Jon Shelby | Affirmative | |
| 3 | Northern Wasco County People's Utility District (PUD) | Paul Titus | Affirmative | |
| 3 | Okanogan County Electric Cooperative, Inc. | Ray Ellis | Affirmative | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Affirmative | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Abstain | |
| 3 | Progress Energy Carolinas | Sam Waters | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Abstain | |
| 3 | Public Utility District No. 1 of Benton County | Gloria Bender | Affirmative | |
| 3 | Public Utility District No. 1 of Franklin County | Linda Boomer | Affirmative | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Affirmative | |
| 3 | Raft River Rural Electric Cooperative | Heber Carpenter | Affirmative | |
| 3 | Salmon River Electric Cooperative | Ken Dizes | Affirmative | |
| 3 | Salt River Project | John T. Underhill | Affirmative | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | | |
| 3 | Umatilla Electric Cooperative | Steve Eldrige | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | Alliant Energy Corp. Services, Inc. | Kenneth Goldsmith | Negative | View |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Affirmative | |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Negative | View |
| 4 | Northern California Power Agency | Fred E. Young | Affirmative | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Negative | |
| 4 | Pacific Northwest Generating Cooperative | Aleka K Scott | Affirmative | |
| 4 | Public Power Council | Nancy Baker | Abstain | |
| 4 | Public Utility District No. 1 of Douglas County | Henry E. LuBean | Negative | View |
| 4 | Public Utility District No. 1 of Snohomish County | John D. Martinsen | Affirmative | |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 5 | AEP Service Corp. | Brock Ondayko | Affirmative | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | |
| 5 | City of Farmington | Clinton J Jacobs | Affirmative | |
| 5 | City of Tallahassee | Alan Gale | Affirmative | |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Negative | View |
| 5 | Deseret Power | Philip B Tice Jr | Affirmative | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entergy Corporation | Stanley M Jaskot | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | IBERDROLA RENEWABLES | Laura Beane | Affirmative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Negative | View |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Affirmative | |
| 5 | New York Power Authority | Gerald Mannarino | Affirmative | |
| 5 | Orlando Utilities Commission | Richard Kinas | Abstain | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Affirmative | |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seattle City Light | Michael J. Haynes | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | | |
| 5 | Southeastern Power Administration | Douglas Spencer | Affirmative | |
| 5 | Southern California Edison Co. | David Schiada | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Abstain | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | U.S. Bureau of Reclamation | Martin Bauer | Affirmative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Affirmative | |
| 6 | AEP Marketing | Edward P. Cox | Affirmative | View |
| 6 | Barry Green Consulting Inc. | Barry Green | Affirmative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Negative | View |
| 6 | Dominion Resources, Inc. | Louis S Slade | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | IBERDROLA RENEWABLES | Kellie J Schreiner | Affirmative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Negative | View |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Affirmative | |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Affirmative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Affirmative | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | Southern California Edison Co. | Marcus V Lotto | Affirmative | |
| 6 | Tampa Electric Co. | Jose Benjamin Quintas | | |
| 6 | Tenaska Power Services Co. | Cliff T Richardson | Abstain | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Affirmative | |
| 7 | Eastman Chemical Company | Lloyd Webb | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Abstain | |
| 8 | Other | Michehl R. Gent | Affirmative | |
| 8 | Volkmann Consulting | Terry Volkmann | Negative | View |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Abstain | View |

| | | | | |
|---|---|---|---|---|
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | SERC Reliability Corporation | Carter B Edge | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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Account Log-In/Register

| Ballot Results | |
|---|---|
| **Ballot Name:** | ATC et al Standards - MOD-001_rc |
| **Ballot Period:** | 8/12/2008 - 8/21/2008 |
| **Ballot Type:** | recirculation |
| **Total # Votes:** | 222 |
| **Total Ballot Pool:** | 234 |
| **Quorum:** | **94.87 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 76.83 % |
| **Ballot Results:** | **The Standard has Passed** |

**Summary of Ballot Results**

| Segment | Ballot Pool | Segment Weight | Affirmative | | Negative | | Abstain | No Vote |
|---|---|---|---|---|---|---|---|---|
| | | | # Votes | Fraction | # Votes | Fraction | # Votes | |
| 1 - Segment 1. | 65 | 1 | 43 | 0.754 | 14 | 0.246 | 3 | 5 |
| 2 - Segment 2. | 9 | 0.7 | 7 | 0.7 | 0 | 0 | 2 | 0 |
| 3 - Segment 3. | 63 | 1 | 46 | 0.836 | 9 | 0.164 | 6 | 2 |
| 4 - Segment 4. | 13 | 1 | 5 | 0.455 | 6 | 0.545 | 2 | 0 |
| 5 - Segment 5. | 39 | 1 | 27 | 0.75 | 9 | 0.25 | 2 | 1 |
| 6 - Segment 6. | 28 | 1 | 19 | 0.76 | 6 | 0.24 | 0 | 3 |
| 7 - Segment 7. | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 8 - Segment 8. | 3 | 0.2 | 2 | 0.2 | 0 | 0 | 1 | 0 |
| 9 - Segment 9. | 6 | 0.5 | 5 | 0.5 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.7 | 5 | 0.5 | 2 | 0.2 | 0 | 0 |
| **Totals** | **234** | **7.1** | **159** | **5.455** | **46** | **1.645** | **17** | **12** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | Ameren Services Company | Kirit S. Shah | Negative | View |
| 1 | American Electric Power | Paul B. Johnson | Negative | View |
| 1 | American Transmission Company, LLC | Jason Shaver | Affirmative | |
| 1 | Arizona Public Service Co. | Cary B. Deise | Affirmative | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Basin Electric Power Cooperative | David Rudolph | Negative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Affirmative | |
| 1 | Brazos Electric Power Cooperative, Inc. | Tony Kroskey | Negative | View |
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | Central Lincoln PUD | Ronald Beck | Affirmative | |
| 1 | Central Maine Power Company | Brian Conroy | | |
| 1 | City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power | Alan L Cooke | Affirmative | |
| 1 | City of Tallahassee | Gary S. Brinkworth | Affirmative | |
| 1 | Consolidated Edison Co. of New York | Edwin Thompson | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | E.ON U.S. LLC | Larry Monday | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | View |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |

| | | | | |
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| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Affirmative | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | View |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Affirmative | |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Affirmative | |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Negative | |
| 1 | Lincoln Electric System | Doug Bantam | Affirmative | |
| 1 | Manitoba Hydro | Michelle Rheault | Affirmative | |
| 1 | Minnesota Power, Inc. | Carol Gerou | Abstain | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Negative | |
| 1 | Oklahoma Gas and Electric Co. | Marvin E VanBebber | Abstain | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Negative | View |
| 1 | Orlando Utilities Commission | Brad Chase | Negative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Negative | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Affirmative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Platte River Power Authority | John C Collins | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Progress Energy Carolinas | Sammy Roberts | Affirmative | |
| 1 | Public Service Electric and Gas Co. | Kenneth D. Brown | Abstain | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Affirmative | |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Negative | |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Affirmative | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | View |
| 1 | Southwest Transmission Cooperative, Inc. | James L. Jones | Affirmative | |
| 1 | Transmission Agency of Northern California | James W Beck | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Affirmative | View |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Western Farmers Electric Coop. | Alan Derichsweiler | | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Affirmative | |
| 2 | Alberta Electric System Operator | Anita Lee | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Affirmative | |
| 2 | Independent Electricity System Operator | Kim Warren | Affirmative | View |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | |
| 2 | Midwest ISO, Inc. | Terry Bilke | Abstain | View |
| 2 | New Brunswick System Operator | Alden Briggs | Affirmative | |
| 2 | New York Independent System Operator | Gregory Campoli | Abstain | View |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | View |
| 3 | Ameren Services Company | Mark Peters | Negative | View |
| 3 | American Electric Power | Raj Rana | Negative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Affirmative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Blachly-Lane Electric Co-op | Bud Tracy | Affirmative | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Affirmative | |
| 3 | City of McMinnville | Rick Rozanski | Affirmative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Negative | View |
| 3 | Clatskanie People's Utility District | Joseph Taffe | Affirmative | |
| 3 | Clearwater Power Co. | Dave Hagen | Affirmative | |
| 3 | Commonwealth Edison Co. | Stephen Lesniak | Affirmative | |
| 3 | Consolidated Edison Co. of New York | Peter T Yost | Affirmative | |
| 3 | Constellation Energy | Carolyn Ingersoll | Affirmative | View |

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|---|---|---|---|---|
| 3 | Consumers Energy | David A. Lapinski | Abstain | |
| 3 | Coos-Curry Electric Cooperative, Inc | Roger Meader | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Affirmative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | View |
| 3 | Grays Harbor PUD | Wesley W Gray | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | View |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Affirmative | |
| 3 | Lincoln Electric System | Bruce Merrill | Affirmative | |
| 3 | Lost River Electric Cooperative | Richard Reynolds | Affirmative | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | Affirmative | |
| 3 | Manitoba Hydro | Ronald Dacombe | Affirmative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Negative | View |
| 3 | Mississippi Power | Don Horsley | Affirmative | View |
| 3 | Nevada Power Co. | Sheryl Torrey | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Northern Indiana Public Service Co. | William SeDoris | Negative | |
| 3 | Northern Lights Inc. | Jon Shelby | Affirmative | |
| 3 | Northern Wasco County People's Utility District (PUD) | Paul Titus | Affirmative | |
| 3 | Okanogan County Electric Cooperative, Inc. | Ray Ellis | Affirmative | |
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Affirmative | |
| 3 | PECO Energy an Exelon Co. | John J. McCawley | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Abstain | |
| 3 | Progress Energy Carolinas | Sam Waters | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | Abstain | |
| 3 | Public Utility District No. 1 of Benton County | Gloria Bender | Affirmative | |
| 3 | Public Utility District No. 1 of Franklin County | Linda Boomer | Abstain | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Affirmative | |
| 3 | Raft River Rural Electric Cooperative | Heber Carpenter | Affirmative | |
| 3 | Salmon River Electric Cooperative | Ken Dizes | Affirmative | |
| 3 | Salt River Project | John T. Underhill | Affirmative | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | | |
| 3 | Umatilla Electric Cooperative | Steve Eldrige | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Negative | |
| 3 | Wisconsin Public Service Corp. | James Maenner | Negative | View |
| 3 | Xcel Energy, Inc. | Michael Ibold | Affirmative | |
| 4 | Alliant Energy Corp. Services, Inc. | Kenneth Goldsmith | Negative | View |
| 4 | Consumers Energy | David Frank Ronk | Abstain | |
| 4 | Florida Municipal Power Agency | Ralph Anderson | Affirmative | |
| 4 | Integrys Energy Group, Inc. | Christopher Plante | Negative | View |
| 4 | Northern California Power Agency | Fred E. Young | Affirmative | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Negative | |
| 4 | Pacific Northwest Generating Cooperative | Aleka K Scott | Affirmative | |
| 4 | Public Power Council | Nancy Baker | Negative | |
| 4 | Public Utility District No. 1 of Douglas County | Henry E. LuBean | Negative | View |
| 4 | Public Utility District No. 1 of Snohomish County | John D. Martinsen | Abstain | |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | |
| 5 | AEP Service Corp. | Brock Ondayko | Negative | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | BC Hydro and Power Authority | Clement Ma | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Affirmative | |
| 5 | City of Farmington | Clinton J Jacobs | Affirmative | |

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|---|---|---|---|---|
| 5 | City of Tallahassee | Alan Gale | Affirmative | |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Negative | View |
| 5 | Deseret Power | Philip B Tice Jr | Affirmative | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | Electric Power Supply Association | Jack Cashin | Negative | View |
| 5 | Entegra Power Group, LLC | Kenneth Parker | Negative | View |
| 5 | Entergy Corporation | Stanley M Jaskot | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | Negative | View |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | IBERDROLA RENEWABLES | Laura Beane | Affirmative | |
| 5 | JEA | Donald Gilbert | Abstain | |
| 5 | Lincoln Electric System | Dennis Florom | Affirmative | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Affirmative | |
| 5 | New York Power Authority | Gerald Mannarino | Affirmative | |
| 5 | Orlando Utilities Commission | Richard Kinas | Abstain | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Affirmative | |
| 5 | Reliant Energy Services | Thomas J. Bradish | Negative | View |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seattle City Light | Michael J. Haynes | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | | |
| 5 | Southeastern Power Administration | Douglas Spencer | Affirmative | |
| 5 | Southern California Edison Co. | David Schiada | Affirmative | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |
| 5 | Tenaska, Inc. | Scott M. Helyer | Negative | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | U.S. Bureau of Reclamation | Martin Bauer | Affirmative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Negative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Affirmative | |
| 6 | AEP Marketing | Edward P. Cox | Negative | |
| 6 | Barry Green Consulting Inc. | Barry Green | Affirmative | View |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Affirmative | |
| 6 | Consolidated Edison Co. of New York | Nickesha P Carrol | Affirmative | |
| 6 | Constellation Energy Commodities Group | Donald Schopp | Negative | View |
| 6 | Dominion Resources, Inc. | Louis S Slade | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Affirmative | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | FirstEnergy Solutions | Mark S Travaglianti | Negative | View |
| 6 | Florida Municipal Power Agency | Robert C. Williams | | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | IBERDROLA RENEWABLES | Kellie J Schreiner | Affirmative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Affirmative | |
| 6 | Louisville Gas and Electric Co. | Daryn Barker | Affirmative | |
| 6 | Luminant Energy | Thomas Burke | | |
| 6 | Manitoba Hydro | Daniel Prowse | Affirmative | |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | PP&L, Inc. | Thomas Hyzinski | Affirmative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Affirmative | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Affirmative | |
| 6 | Reliant Energy Services | Trent Carlson | Negative | View |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | Southern California Edison Co. | Marcus V Lotto | Affirmative | |
| 6 | Tampa Electric Co. | Jose Benjamin Quintas | | |
| 6 | Tenaska Power Services Co. | Cliff T Richardson | Negative | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Affirmative | |
| 7 | Eastman Chemical Company | Lloyd Webb | Abstain | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Abstain | |
| 8 | Other | Michehl R. Gent | Affirmative | |
| 8 | Volkmann Consulting | Terry Volkmann | Affirmative | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| | Commonwealth of Massachusetts Department | | | |

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|---|---|---|---|---|
| 9 | of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | | |
| 9 | Oregon Public Utility Commission | Jerome Murray | Affirmative | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Negative | View |
| 10 | Midwest Reliability Organization | Larry Brusseau | Negative | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | SERC Reliability Corporation | Carter B Edge | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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*Washington Office:* 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

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